CANADIAN UTILITIES LIMITED

CU RESOURCES LIMITED

ALBERTA POWER LIMITED

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

NORTHWESTERN UTILITIES LIMITED

CU ENGINEERING LIMITED

CU ETHANE LIMITED

1980 ANNUAL REPORT

CANADIAN UTILITIES LIMITED

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Photo Credits

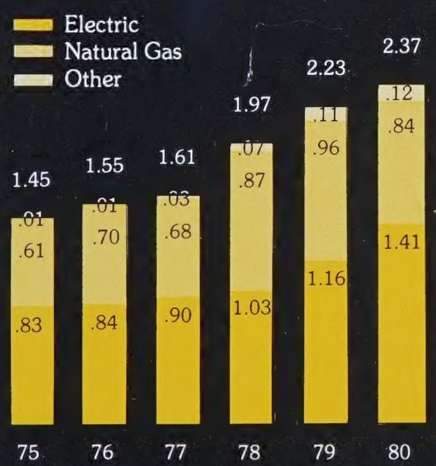
Pictures appearing in this year's annual report of company operations were photographed during 1980 by the company's assignment photographer, Alex Macdonald of Edmonton.

HIGHLIGHTS

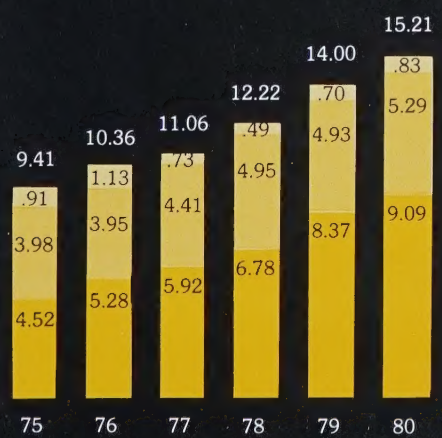
	1980	1979	Increase
Revenues (thousands)			
Natural gas	**$581,677**	$477,929	$103,748
Electric	**149,847**	124,647	25,200
Other	**26,172**	23,152	3,020
Total	**$757,696**	625,728	131,968
Net earnings attributable to common shares (thousands)	**$ 49.273**	41,809	7,464
Earnings per common share (per share)	**$ 2.37**	2.23	.14
Common shareholders' equity per share (at year-end fully diluted)	**$ 15.21**	14.00	1.21
Dividends paid per share			
Annual	**$ 1.14½**	1.01½	.13
Fourth quarter	**$ .30½**	.28	.02½
Average common shares outstanding	**20,817,623**	18,741,188	2,076,435
Capital expenditures (thousands)	**$266,984**	$178,775	$ 88,209
Customers at year-end			
Natural gas	**519,997**	489,848	30,149
Electric	**128,820**	120,133	8,687

Segmented Information

Earnings Per Common Share (in dollars) before extraordinary items

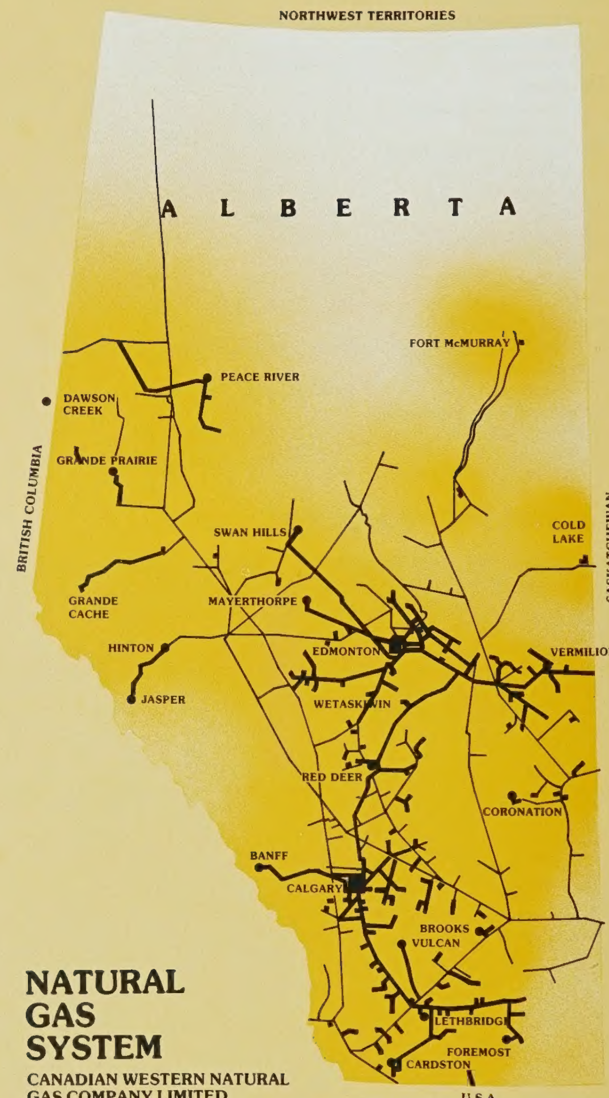


Equity in Common Shares (in dollars)



CANADIAN UTILITIES LIMITED

SYSTEM MAPS



NATURAL GAS SYSTEM

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

NORTHWESTERN UTILITIES LIMITED

MAJOR TRANSMISSION AND FIELD GATHERING PIPELINES

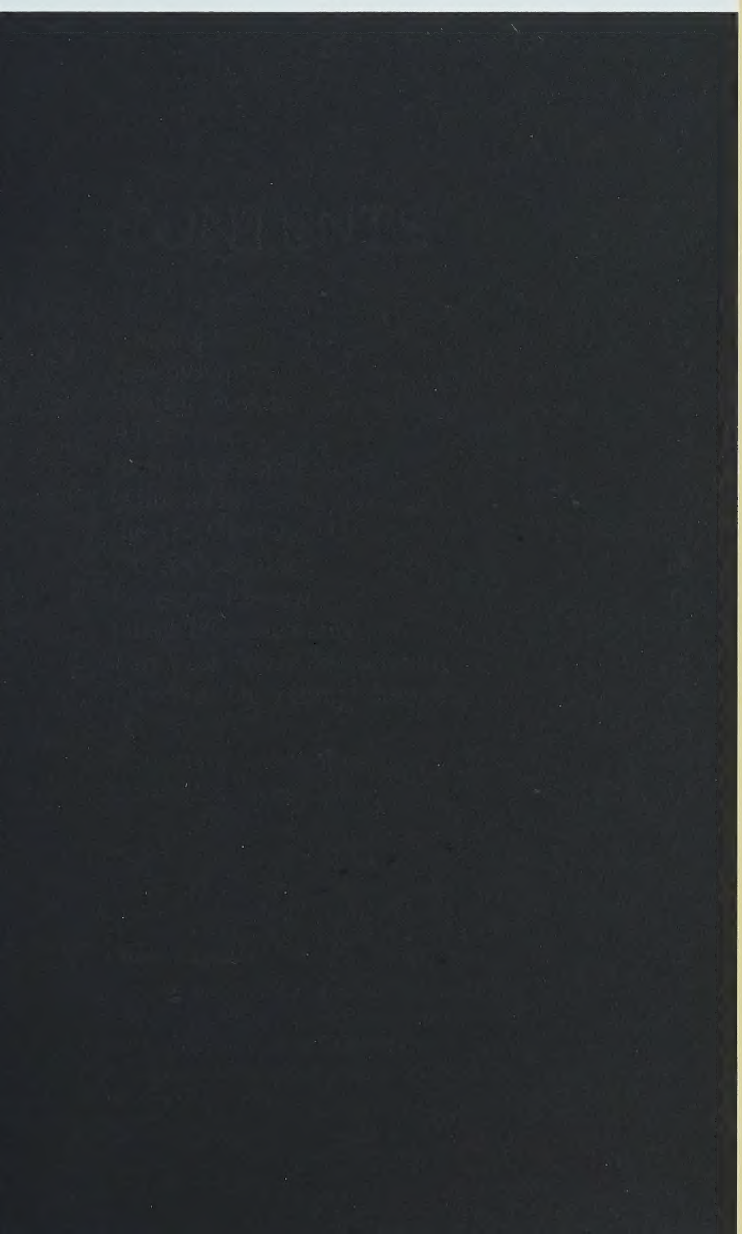
MAJOR PIPELINES OWNED BY OTHERS

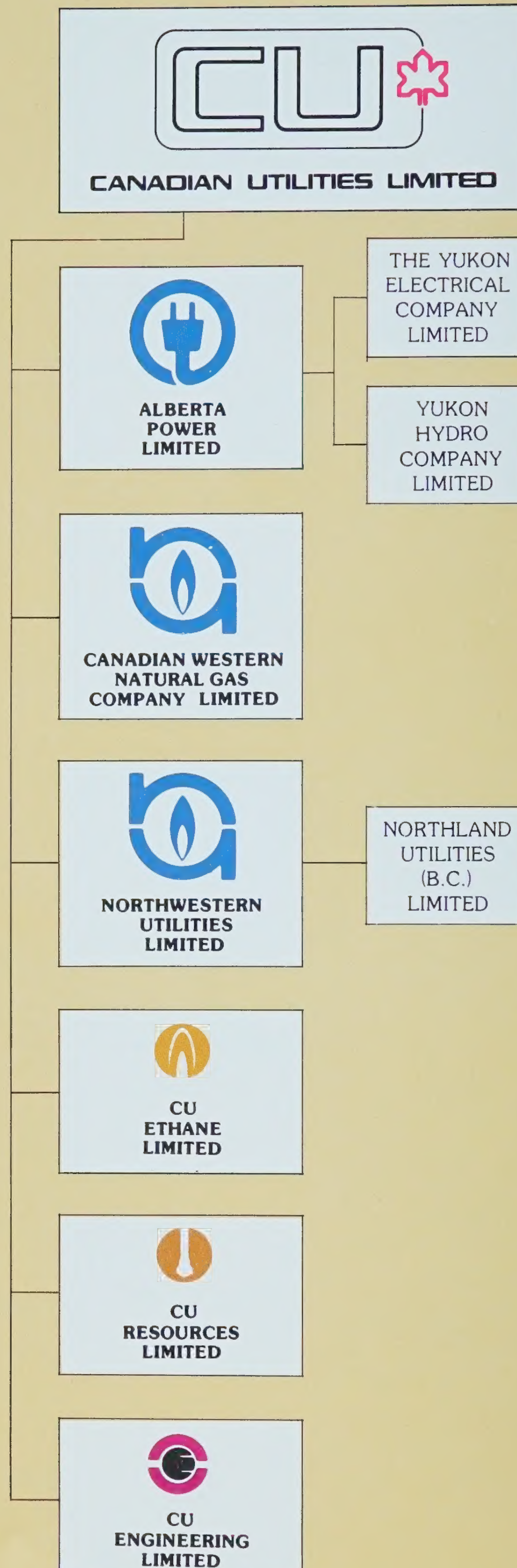
ELECTRIC SYSTEM

ALBERTA POWER LIMITED

SERVICE AREA
MAJOR TRANSMISSION
GENERATING PLANTS
POWER LINES OWNED BY OTHERS
OTHER ELECTRIC UTILITIES

CANADIAN UTILITIES LIMITED





An employee of The Yukon Electrical Company Limited performs maintenance tasks in Whitehorse with the aid of a vehicle known as a "Polecat".


KLONDIKE
POLECAT
THE YUKON ELECTRICAL COMPANY LTD

TO THE SHAREHOLDERS

The first year of this new decade was very eventful for Canadian Utilities Limited, bringing higher levels of earnings and assets, and a major change in the ownership of the company.

Net earnings attributable to common shares rose to $49,273,000 ($2.37 a common share) from $41,809,000 ($2.23 a share) in 1979.

Electric sales to ultimate customers (not including wholesale sales to other utilities) increased to 2,994 million kilowatt hours from 2,779 million kilowatt hours, an increase of more than 7%.

Natural gas sales for 1980 were 391.8 petajoules (371.5 billion cubic feet) compared to 391.5 petajoules (371.2 billion cubic feet) in the previous year. All the increase in sales resulting from an expanding residential and commercial market was offset by the influence of weather in 1980, which was much milder than in 1979, together with some fluctuations in special purpose industrial sales.

One of the most encouraging features of the year was the basic underlying market growth provided by new customers added to the electric and gas systems with 38,834 new accounts in total being acquired during 1980, an increase of 6%.

On June 19, 1980 ATCO Ltd., through a subsidiary company, acquired the 58.1% controlling interest in Canadian Utilities previously held by IU International Corporation.

ATCO is an Alberta controlled organization whose worldwide activities, in addition to energy and resource related fields, include residential housing, the manufacture and distribution of prefabricated structures, and land and property development.

The repatriation of ownership accomplished by ATCO's purchase of shares places CU well into the ranks of companies with the very highest percentage of Canadian ownership, which should facilitate continued gas and oil exploration as well as other new growth opportunities that may be pursued in the future.

The year was marked by severely high interest rates and increasing inflation. After successfully operating throughout 1979 without rate increases, all the company's utility operations were compelled to apply to the Public Utilities Board for substantial rate relief in the 1980 fiscal year. The Public Utilities Board allowed interim rate increases for all three companies, but in two cases the rates approved were lower than those requested. Recent changes in the legislation give the Board the option of utilizing a two-year time span to adjust revenues in accordance with its final decision on an application. The holding back of part of the increases applied for, plus lower-than-forecast gas sales in the final portion of the year, reflecting mild weather, caused the earnings for the natural gas operations in 1980 to be slightly less than those of the previous year.

A decision relating to one of the 1980 applications has been issued by the Public Utilities Board since year-end. It sets a new allowable rate of return of 14.75% on the portion of the Canadian Western Natural Gas Company's rate base which is financed by common equity. It did not direct any changes in the interim rates which were still in effect at the end of 1980.

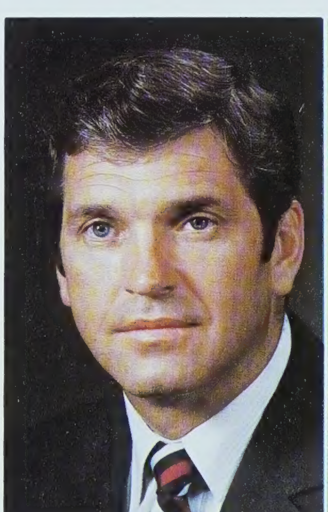
Applications for rates required for both electric and gas service in 1981 have been filed and are under review by the Public Utilities Board. Further increases may be required in 1981 as changes occur in operating conditions, such as adjustments in purchased gas costs and energy taxes.

The excise tax payable on natural gas distributed by the companies, which was imposed by the federal budget and the new National Energy Program, typifies an increase completely beyond management's control. For the full year 1981, the excise tax may give rise to a tax bill of more than $120 million.

It is now known that consumers served by Canadian Utilities' companies will once again benefit from a 95% refund of federal income taxes as well as 100% of Alberta income taxes paid by those companies. Recent announcements confirm a federal government decision not to pursue the change in legislation that would have reduced the federal portion of the refund to only 50% of taxes paid.

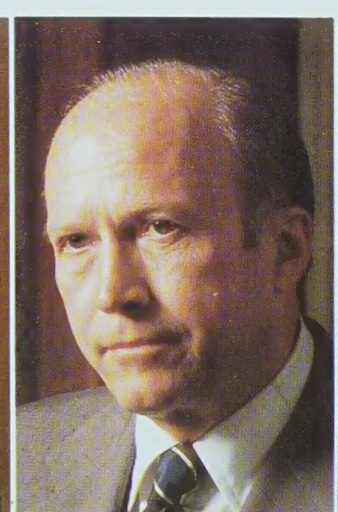
At year-end the company's assets totalled $1,332,026,000, up 30% over

Board of Directors



W. L. Britton

G. L. Crawford, Q.C.



E. W. King

P. L. P. Macdonnell, Q.C

the figure of a year ago. For the first time expenditures within a single year on new plant and equipment were more than $200 million. Expenditures in 1980 were $267 million, and 1981 expenditures are expected to remain above the $200 million level. The 375-megawatt Unit #5 at the Battle River Generating Station is the largest project on which expenditures are still in progress, although it is nearing completion and should be in service as planned by the summer of 1981.

Gas exploration expenditures on behalf of the utility subsidiaries were increased to $15 million and, of the 61 wells drilled by the utilities and their partners, 30 were known to be commercially successful, 18 are awaiting further testing and evaluation, and 13 were abandoned.

Funds for expansion came in large part from the issue of $50 million in 10.24% preferred shares (Series D) and $100 million in 12% debentures. Just prior to the end of 1980 the company filed a preliminary prospectus relating to a further issue of preferred shares. This $55 million issue of 10.12% preferred shares (Series E) was completed in February 1981.

The fourth quarter dividend on common shares was raised to 30.5 cents a share from 28 cents. This was the tenth time in the past nine years that the company has increased its common dividend.

Economic growth in Alberta continued to exceed national averages in practically every respect and this situation is expected to continue, even though possibly at reduced rates, for the foreseeable future. The province will not approach its full growth potential, however, until a satisfactory agreement is reached between the federal and provincial governments on energy pricing, and the oil sands and heavy oil projects are permitted to go ahead. The company also shares the concerns expressed by many Canadians that the National Energy Program will fall far short of its goals of increasing future energy supplies and attaining self-sufficiency, until there are some significant modifications that will restore the confidence of the resource development industry.

The company was deeply saddened by the death on July 8 of Wilson G. Sterling, Senior Vice-President, Chief Operating Officer and a Director of Alberta Power Limited. He had served with the electric utility company since 1953 and made an outstanding contribution to the industry in Alberta. He was succeeded by Keith Provost, a Vice-President of Alberta Power since 1971.

Following the change in the ownership of the controlling interest in Canadian Utilities, Messrs. J. M. Seabrook, R. F. Calman, W. D. H. Gardiner and W. S. McLeese submitted their resignations as members of the company's Board of Directors. This event marks the conclusion of a very long association between Canadian Utilities and IU International Corporation. CU and its associated companies have benefited significantly from the encouragement offered by that corporation and its representatives dating from the pioneer days of gas and electric services in western Canada and continuing over a span of 56 years.

R. D. Southern, Chairman and Chief Executive Officer of ATCO Ltd.; W. L. Britton, a partner in the Calgary law firm of Bennett Jones; C. S. Richardson, Senior Vice-President, Finance, ATCO; and N. W. Robertson, Senior Vice-President and Chief Operating Officer, ATCO, joined the Canadian Utilities Board of Directors on June 20, 1980.

In March 1981, E. W. King, President of Canadian Utilities, became Chief Executive Officer, and R. D. Southern and C. S. Richardson were appointed Chairman and Deputy Chairman respectively. These appointments followed the resignations of J. E. Maybin, formerly Chairman and Chief Executive Officer, and K. A. Biggs, formerly Senior Vice-President, Finance and a Director.

The success of the past year would not have been possible without the enthusiastic support and conscientious efforts of the 4,500 employees who make up the Canadian Utilities organization. Their demonstrated ability to respond positively to new challenges is among the company's most valuable assets and is a sound basis for confidence in the future.

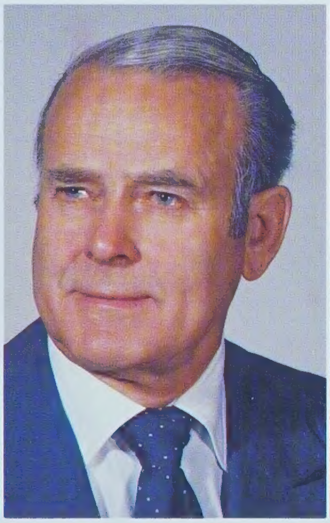
On behalf of the Board of Directors

E. W. King

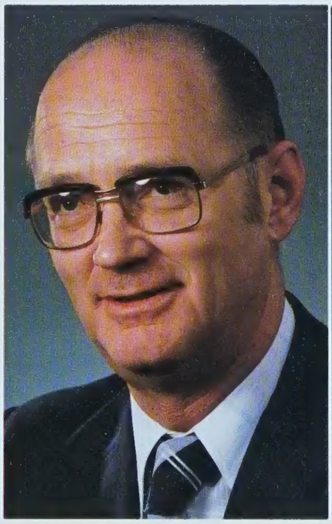
E. W. King, President and Chief Executive Officer

March 5, 1981

D. R. B. McArthur



W. S. McGregor



C. S. Richardson

N. W. Robertson

R. D. Southern

NATURAL GAS OPERATIONS

The company's natural gas operations are conducted by two subsidiaries, Canadian Western Natural Gas Company Limited, which serves southern Alberta including Calgary and Lethbridge, and Northwestern Utilities Limited, whose service area is north-central Alberta including the communities of Edmonton, Red Deer, Fort McMurray and Grande Prairie. A Northwestern Utilities subsidiary, Northland Utilities (B.C.) Limited, supplies Dawson Creek and district in northeastern British Columbia.

In spite of high interest rates and energy industry uncertainties, gas operations recorded a growth rate of more than 6%, adding 30,149 new customers, bringing the total number served to 519,997. Net fixed gas utility assets rose to $424.2 million from $362.1 million in 1979.

During 1980, Canadian Western upgraded a section of natural gas distribution line supplying Calgary's downtown, transformed by a multitude of new office towers. The value of building permits issued in Calgary and metropolitan Edmonton in 1980 exceeded $3 billion.

Earnings attributable to common shares were $17.6 million compared to $18.1 million in the previous year and, expressed in earnings per common share, represent $0.84 in 1980 compared to $0.96 in the previous year. Shareholders' average equity investment increased 7% in the year.

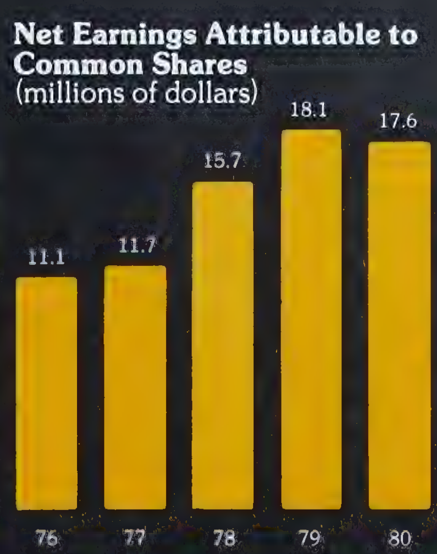
Earnings and Rates

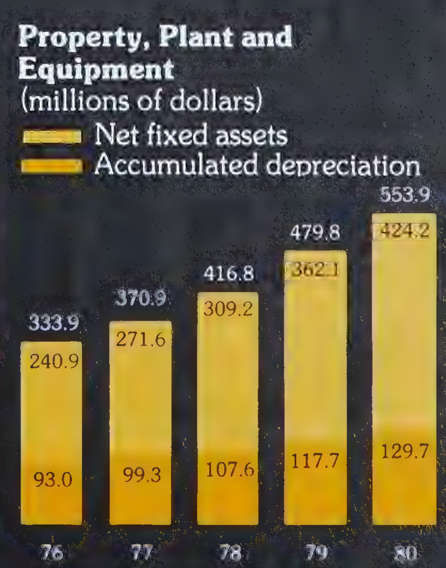
The 1980 earnings reflect Alberta Public Utilities Board decisions to hold back a total of $5.4 million from interim rate increases granted to the natural gas utilities in the latter part of the year. Hearings into the rate applications began late in 1980 and a decision issued since year-end on Canadian Western's case set a new allowable rate of return at 14.75% on the portion of the company's rate base financed by common equity. The decision did not direct any change in the interim rates in effect at the end of 1980. The utilities' request for uniform rates for equivalent service will be considered in the second phase of the hearings.

Also, warmer than normal temperatures had a negative effect on sales and earnings.

Three other rate increases were approved during 1980. The provincial support price for natural gas, established under the Alberta Price Protection Plan, was changed on February 1 and September 1, and the federal government introduced an excise tax of 28 cents per gigajoule effective November 1. The gas utilities applied for and received Utilities Board authorization for higher rates to recover increased costs effective February 1, October 1 and November 1.

The British Columbia Public Utilities Commission authorized an increase in rates of 30.5¢ per thousand cubic feet effective in November, 1980 for customers of Northland Utilities (B.C.) Limited due to the introduction of the federal excise tax. In March 1980 the British





Columbia government eliminated the 4% social services tax on natural gas for residential use.

Both Canadian Western and Northwestern were unsuccessful in their attempt to negotiate a lower price for natural gas purchased from suppliers on existing contracts. This setback was a result of a judgment issued by the Court of Appeal of Alberta that outlined conditions under which arbitration would be conducted to determine a contractual price.

Costs and Revenues

Natural gas revenues were $581.7 million in 1980, up 21.7% over 1979. Operating expenses, which include the costs of natural gas, operations and maintenance, depreciation and property and franchise taxes were $538.0 million, compared to $437.1 million in 1979.

Purchased gas costs representing 79.3% of operating expenses, were $426.8 million in 1980, up $84.5 million over the previous year. Gas costs were net of $117.8 million in rebates from the Alberta government under the Natural Gas Price Protection Plan. The imposition in November of the federal excise tax on natural gas increased costs by $19.8 million.

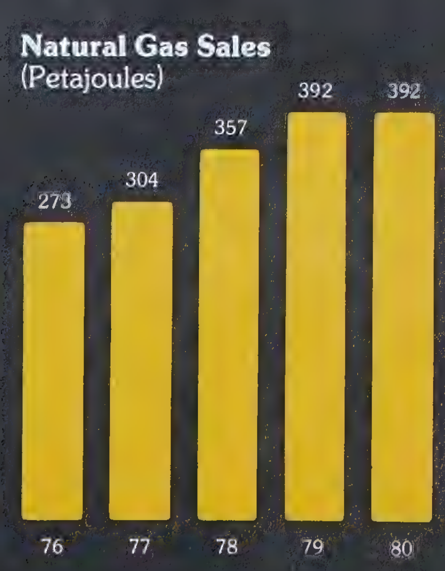
In 1981, the federal government's National Energy Program will have a significantly greater impact on the company's gas operations and their customers. With the excise tax in effect for the full year, and a further increase scheduled for July 1, 1981, the 1981 excise tax cost is projected to reach $122 million. As well, an 8% tax on net revenue from production of natural gas became effective January 1, 1981. Details of the National Energy Program have not been finalized and there may well be changes that will impact on future costs.

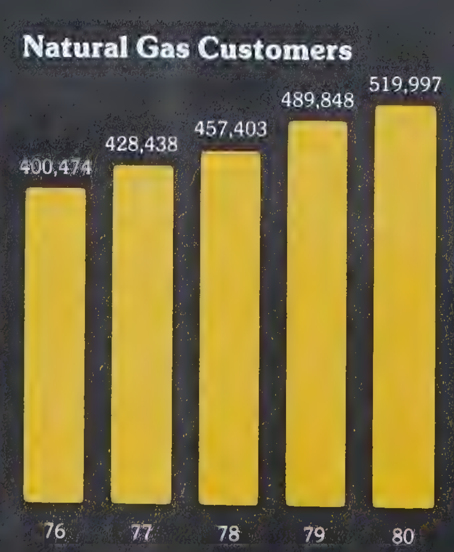
The company shares the concerns expressed by many Canadians that the National Energy Program will not reach its goals of increasing future energy supplies and attaining energy self sufficiency.

Natural Gas Sales

Natural gas sales were 391.8 petajoules (371.5 billion cubic feet), compared to 391.5 petajoules (371.2 billion cubic feet) in 1979. A combination of warmer than normal temperatures and fluctuations in some special purpose industrial sales offset system-wide growth in number of customers. In terms of degree days, a measure of space heating requirements, 1980 was warmer than normal while 1979 was colder than normal.

Consumption per customer continued to decrease in the residential and commercial markets, further offsetting the effect of customer growth on the volume of sales. This trend is expected to continue as the cost of natural gas increases and more attention is paid to conservation efforts and improved building standards.





Capital Expenditures

Capital expenditures on gas operations in 1980 totalled $75.6 million compared to $64.5 million in 1979. Most of the expenditures were for the expansion of transmission and distribution facilities to meet the needs of a growing population. Canadian Western connected 15 new wells to its system — 10 in the Carbon area and five at Entice. Northwestern Utilities began installation of two compressors at the Viking field to increase delivery of natural gas from its own reserves.

Natural Gas Supply

The major portion of the utilities' supplies of natural gas is purchased under long-term contracts with producing companies. The balance is supplied from a combination of purchases from export and pipeline companies or is obtained from company-owned properties. The utilities also utilize natural gas storage for system supply balancing.

According to recent estimates, company-owned gas reserves amounted to 890 petajoules. Under long-term contract were 3,478 petajoules of energy in the form of gas reserves from fields from which natural gas is purchased; and an additional 2,388 petajoules will be available for purchase in the future from oilfield gas caps connected to the transmission systems and from fields where the estimated gas producing life exceeds the term of the existing gas purchase contracts.

In addition, to ensure that future supply requirements are met, there are agreements with five major export companies enabling the utilities to call for quantities of base-load and peak-load gas as required. The security of the natural gas supply is also assisted by the policy of the Alberta government whereby local customers have priority over out-of-province demands for natural gas.

Both utilities continued their own exploration and development programs during the year, acquiring additional petroleum and natural gas leases and participating in the drilling of 61 wells. Of the wells drilled, 30 were successful and 18 others are still being evaluated. The cost of successful wells was added to assets; the cost of unsuccessful prospects will be recovered, with Public Utilities Board approval, from border flowback funds. Under the border flowback program, all Alberta gas producers, including Canadian Western and Northwestern, receive a pro rata share of the extra revenues generated by the differential in price between gas exported to the U.S.A. and that marketed in Canada.

Future Developments

Canadian Western has announced plans for a new head office to be constructed at 8th Street and 11th

Placing high-pressure distribution line to supply natural gas service to the new McKenzie subdivision in Calgary meant blasting a 61-metre ditch through the rock bed under the Bow River at this site.

Gas Operations Earnings Contribution

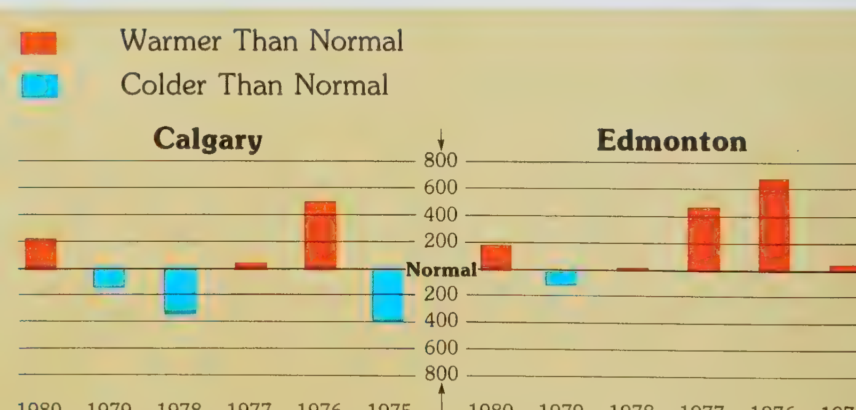
	1980	1979	1978	1977	1976	1975	Annual Growth Rate 1975-1980
			(Millions of dollars)				(Per cent)
Natural gas revenues	**581.7**	477.9	431.8	318.7	216.5	141.8	32.6
Operating expenses							
Natural gas supply	**426.8**	342.3	315.5	221.3	134.8	70.9	
Operating and maintenance	**71.1**	61.1	49.7	42.8	36.3	29.1	
Taxes — other than income	**28.3**	23.4	22.5	18.1	14.3	9.6	
Depreciation	**11.9**	10.3	8.9	7.1	6.6	6.8	
	538.1	437.1	396.6	289.3	192.0	116.4	35.8
	43.6	40.8	35.2	29.4	24.5	25.4	11.5
Income deductions	**15.4**	10.5	8.5	8.9	7.6	8.5	
Income taxes	**7.6**	9.2	8.0	6.4	5.3	6.8	
Net earnings	**20.6**	21.1	18.7	14.1	11.6	10.1	15.3
Preferred dividend requirements	**3.0**	3.0	3.0	2.4	.5	.5	
Balance attributable to common shares	**17.6**	18.1	15.7	11.7	11.1	9.6	12.9
Mid-year common equity investment	**109.2**	100.3	86.7	75.5	68.3	60.2	12.6

Avenue, S.W. in Calgary for occupancy in the summer of 1982. Canadian Western is also proceeding with plans for a new operations centre in the Midnapore area that will enhance service to customers in the southern part of Calgary.

The delay in commencement in oil sands and heavy oil extraction projects in the Fort McMurray and Cold Lake/Grand Centre areas will temper the demand for utility services in those areas; however, several major petrochemical and refinery projects in the planning or approval stages will help sustain a buoyant economy in Alberta and continued growth for Canadian Utilities' natural gas operations.

The company's natural gas utility operations participated in the drilling of 61 wells in Alberta in 1980 to find and develop company-owned gas reserves. A non-utility subsidiary, CU Resources Limited, searches for oil in Alberta and northeastern British Columbia.

Alberta Power's Battle River Generating Station near Forestberg has been the scene of almost continuous expansion in recent years. Latest addition is the 375-megawatt Unit #5, which will more than double the plant's capacity to 740 megawatts. The camp units in the foreground house the temporary workforce employed on construction of the new unit.



Normal — 5,290 Degree Days			
Year	Degree Days	Colder or Warmer ( ) Than Normal: Number	Per Cent
1980	5,082	(208)	(3.9)
1979	5,366	142	2.7
1978	5,592	358	6.8
1977	5,289	(63)	(1.2)
1976	4,885	(494)	(9.2)

Normal — 5,581 Degree Days			
Year	Degree Days	Colder or Warmer ( ) Than Normal: Number	Per Cent
1980	5,396	(185)	(3.3)
1979	5,636	120	2.2
1978	5,530	(10)	(0.2)
1977	5,124	(465)	(8.5)
1976	4,891	(709)	(12.7)

ELECTRIC OPERATIONS

Alberta Power Limited, the company's electric utility subsidiary, now serves 372 communities in east-central and northern Alberta and five communities in the Northwest Territories including the Town of Hay River. An Alberta Power subsidiary, The Yukon Electrical Company Limited, serves 18 communities in the Yukon including the City of Whitehorse.

In 1980, 8,687 new electric utility customers were added, bringing the year-end total to 128,820. Included in this total were 24,239 farm customers of whom 23,100 were members of 167 Rural Electrification Associations.

Energy sales to ultimate customers increased by 7.7% to 2,994 million kilowatt hours. An additional 33 million kilowatt hours were sold to other utilities. The peak load increased to 607 megawatts from 573 megawatts the previous year.

The following table shows 1980 electric sales to the various customer categories (not including 33 million kilowatt hours sold to other utilities).

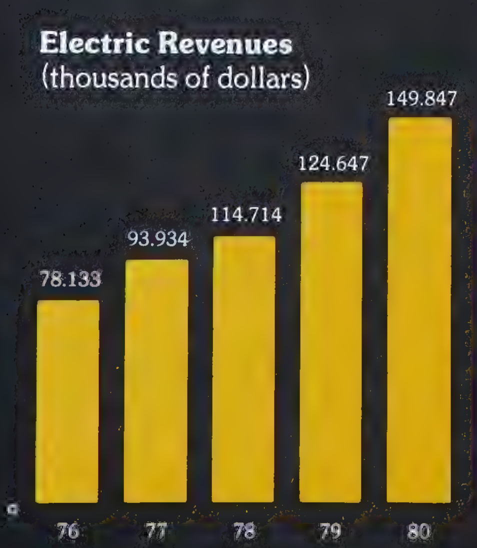
	Thousands of Kilowatt Hours	Per Cent of Total
Industrial	1,501,903	50.2
Commercial	586,279	19.6
Residential	556,529	18.6
REA and Others	349,043	11.6
TOTAL:	2,993,754	100.0

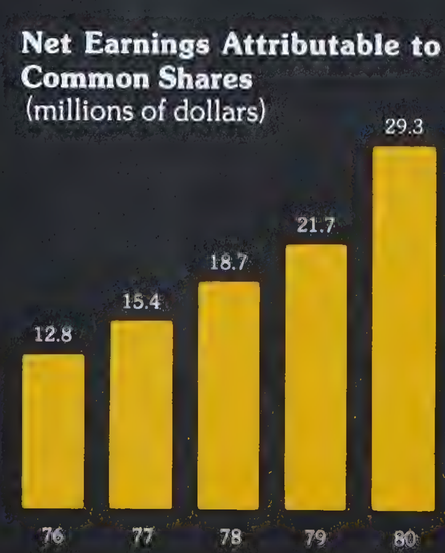
Electric revenues were $149.8 million, up from $124.6 million in 1979. This growth in revenue was a result of increased sales and a 12% increase in rates which took effect on January 1, 1980.

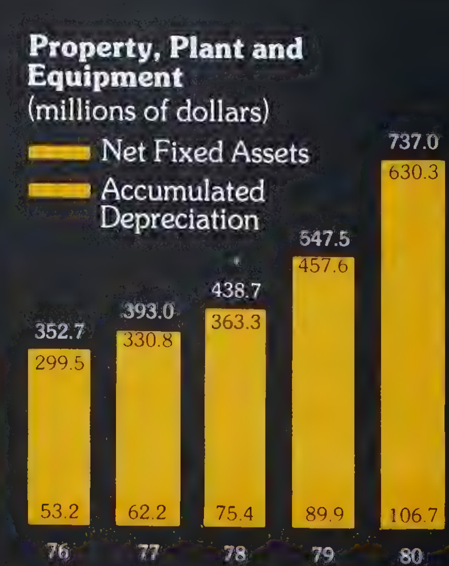
Earnings attributable to common shares were $29.3 million compared to $21.7 million in the previous year and, expressed in earnings per common share, represent a 22% increase from $1.16 to $1.41 in the year. The shareholders average equity investment increased 9% in the year.

Rates

Alberta Power filed an application with the Alberta Public Utilities Board in May 1980, seeking rate increases effective July 1, 1980. This application was a result of increases in cost of service and the Board's decision to allow the company to adopt the "normalized — all taxes paid" method of accounting for income taxes. However, following the federal government's announced intention to reduce to 50% from 95% the portion of federal taxes rebated to the customer, the company withdrew its application and re-filed in October, 1980 using the "flow through" method of accounting for income taxes. In this application the company sought a revenue increase of $27.7 million effective January 1, 1981 to recover increased costs







of service and to provide a 15.5% rate of return on common equity. The Public Utilities Board has not yet rendered its final decision in this matter, although it has allowed the company to collect additional revenue of $17 million by approving an interim rate increase effective January 1, 1981.

(On February 5, 1981 the federal government decided to reinstate its policy of rebating 95% of federal taxes, and the company is studying the impact of this decision on its operations.)

Construction Activity

Alberta Power's expenditures for additions to property, plant and equipment during the year were $190 million — up 72% over the 1979 level. Of this total, $118 million was spent on construction of the 375-megawatt Unit #5 at the Battle River Generating Station. This $242 million addition will more than double that station's generating capacity to 740 megawatts when commissioned on schedule this summer. Half of the unit's output will be sold to the City of Edmonton for a seven-year period.

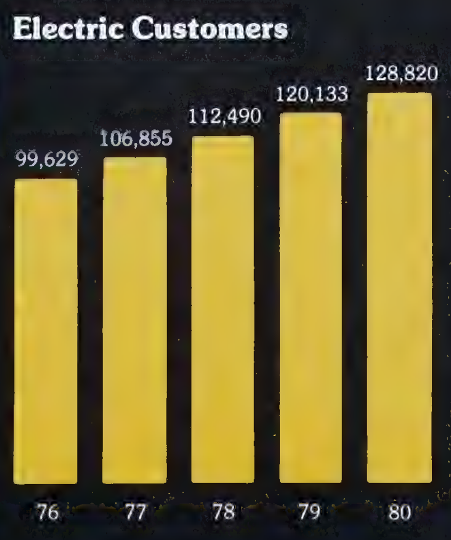
A total of $11 million was expended during the year on modifications to the company's H. R. Milner Generating Station at Grande Cache. These modifications will provide increased peaking capability and improved coal-burning capability, while meeting environmental standards.

A second 45-cubic-metre dragline, which will be leased by the company and used to mine coal for the Battle River Generating Station, is expected to be in operation by mid-summer.

The total expenditure on transmission and subtransmission projects was $26 million, more than double the 1979 level. Projects included the 240-kilovolt Cordel Switching Station at Battle River ($7 million); a 58-kilometre, 240-kilovolt double circuit steel-tower line from Sheerness to the Red Deer River for connection to Brooks ($6.9 million); a 32-kilometre, 144-kilovolt line from Drumheller to Wintering Hills ($1.0 million); and a 100-kilometre section of 144-kilovolt line from Vilna to Bonnyville, delayed from the fall of 1979 to August 1980 because of difficulties in obtaining approvals and rights-of-way ($3.2 million).

Construction of a 145-kilometre, 240-kilovolt line from Battle River to Sheerness has been delayed by difficulties in obtaining rights-of-way in the area. A further $18.4 million was applied to the construction and upgrading of various distribution systems.

Alberta Power continued to experience problems in obtaining necessary regulatory approvals and rights-of-way required for provision of service to its customers. A program of public information was initiated during 1980 to improve relationships with landowners and minimize problems associated with the acquisition of land for facilities. Alberta Power recognizes the importance of farm lands to the long-term prosperity of both the province and the company, and is determined to maintain amicable



relations with landowners essential to the timely construction of transmission facilities.

The Energy Resources Conservation Board turned down the company's August 1979 application for approval to construct and operate transmission facilities to interconnect with the power system in Saskatchewan. Alberta Power is reassessing the benefits of this interconnection and will prepare a new application should circumstances warrant.

Preliminary site preparation was undertaken in 1980 at the location of the Sheerness Generating Station, with construction to get under way in April of this year. As the 750-megawatt Sheerness Station will have capacity surplus to Alberta Power's needs for several years, an agreement has been entered into with another utility to share on an equal basis in the ownership of the plant, with Alberta Power acting as the managing owner. Contracts were let during 1980 for the turbines and boilers, with delivery scheduled so that the first unit can be commissioned in 1985 and the second unit to follow in 1986.

Future Development

The October federal budget has had the direct effect of increasing the company's 1981 fuel cost by an estimated $800,000 and is expected also to reduce the revenue received from oil industry customers due to the anticipated reduction in oil production and exploration activity.

Capital expenditures of $166 million are anticipated in 1981. The completion of Battle River #5, the dragline and a start on construction of the Sheerness plant will require $100 million. A further $40 million will provide additional transmission and subtransmission lines with $26 million going to new distribution lines and other facilities.

During 1980, the Alberta Energy Resources Conservation Board awarded Alberta Power the right to serve the Esso Resources heavy oil project in the Cold Lake area. The company is tentatively planning to install approximately 600 kilometres of 240-kilovolt transmission line to be in service in 1985 to serve this major load.

Delays in government approval of the Cold Lake and Alsands projects create some uncertainty in the planning required to supply these customers.

The company undertook with another Alberta utility and a major coal company to study the feasibility of constructing a coal-fired plant to provide export power for the western United States. A decision whether or not to proceed with the lengthy approvals process is expected to be made during 1981.

In response to an invitation from the provincial government for proposals to develop the hydroelectric potential of the Peace River near Dunvegan, the company

An artist's rendering shows approximately how the Sheerness Generating Station will look when completed at its location near Hanna in southern Alberta. Construction on the 750-megawatt station is scheduled to begin early in 1981.

Electric Operations Earnings Contribution

	1980	1979	1978	1977	1976	1975	Annual Growth Rate 1975-1980
			(Millions of dollars)				(Per cent)
Electric revenues	**149.8**	124.6	114.7	93.9	78.1	57.9	20.9
Operating expenses							
Operating and maintenance	**74.4**	61.7	51.9	42.3	35.4	27.0	
Taxes — other than income	**5.1**	4.5	4.2	3.7	2.7	2.2	
Depreciation	**16.0**	14.6	13.8	11.4	8.8	6.3	
	95.5	80.8	69.9	57.4	46.9	35.5	21.9
	54.3	43.8	44.8	36.5	31.2	22.4	19.4
Income deductions	**3.9**	9.1	8.7	10.2	12.3	7.2	
Income taxes	**11.8**	6.7	11.1	5.8	3.1	1.6	
Net earnings	**38.6**	28.0	25.0	20.5	15.8	13.6	23.2
Preferred dividend requirements	**9.3**	6.3	6.3	5.1	3.0	2.9	
Balance attributable to common shares	**29.3**	21.7	18.7	15.4	12.8	10.7	22.3
Mid-year common equity investment	**181.3**	149.7	113.2	98.8	84.8	65.3	22.7

joined with Edmonton Power and the City of Medicine Hat to file a joint submission at the end of June. The submission calls for a 1,000-megawatt hydroelectric development with a completion date tentatively set at 1990. A decision from the government on the two submissions received is expected during 1981.

Territories

Alberta Power sought and received a 6.5% rate increase in the Northwest Territories effective September 1, 1980. The Yukon Electrical Company Limited is preparing to file an application for rate increase in the Yukon, effective May 1, 1981. Fuel adjustment clauses in both territories enable the company to pass on fuel increases to its customers without the necessity of a formal hearing.

A total of $1.3 million of capital was spent, largely on distribution projects, in the Yukon during the year.

A dragline removes overburden at the coal field adjacent to Alberta Power's Battle River Generating Station. Most electricity produced in Alberta comes from plants fueled by coal, which Alberta has in abundance, but large-scale hydro developments are in the planning stages.

OTHER OPERATIONS

CU Engineering Limited

CU Engineering maintained a high level of activity during 1980, primarily in Alberta but also elsewhere in Canada and overseas.

Among the major projects in which the company was engaged were:

- A pipeline extension and relocation at the Syncrude plant near Fort McMurray, Alberta.
- Preparatory work in connection with the extension of a natural gas transmission line to the Maritime provinces.
- A gas distribution project in Bangladesh sponsored by the Aslan Development Bank.

In addition, CU Engineering was chosen by the Canadian government to participate in an oil and gas seminar and trade mission in Australia, a promising market for the company's services.

CU Engineering offers a wide range of consulting services related to gas and electric utility operations. Such services include feasibility studies, design, commissioning and operation of utility systems. The company also does work for municipalities in connection with road, sewer and water distribution systems.

CU Ethane Limited has a 50% interest in this ethane extraction plant on Edmonton's southern outskirts. Ethane stripped from natural gas is used for the manufacture of ethylene, an important product of Alberta's burgeoning petrochemical industry.

CU Engineering's clients are government agencies, utility companies outside the Canadian Utilities group, oil and gas producers and industrial and petrochemical enterprises.

The company has its own professional staff which can be augmented by engineers and technicians from other units of the Canadian Utilities organization.

CU Ethane Limited

CU Ethane Limited and Dome Petroleum Limited are joint partners in an ethane extraction plant located in Edmonton.

The plant was completed in 1978 at a cost of $45 million and forms part of the $2 billion Alberta petrochemical industry. At the plant, ethane and natural gas liquids (propane pluses) are extracted from natural gas flowing into Edmonton. Ethane is delivered to the provincial ethane gathering system and is used as feedstock in the production of ethylene at a facility near Red Deer. Ethane and natural gas liquids surplus to provincial needs are exported.

During 1980, ethane production exceeded 760,000 cubic metres (4.8 million barrels) and natural gas liquids output was 529,000 cubic metres (3.3 million barrels).

CU Ethane continues to seek opportunities to expand its operations in the petrochemical field.

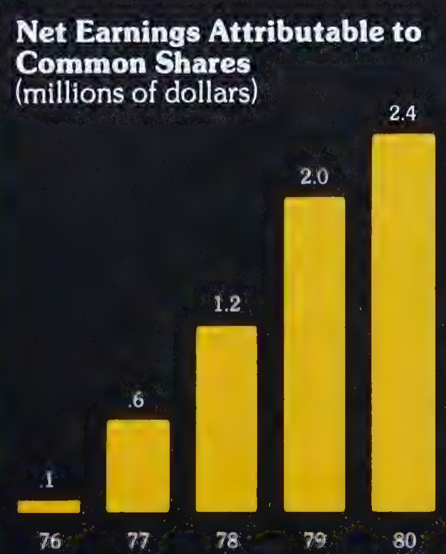
CU Resources Limited

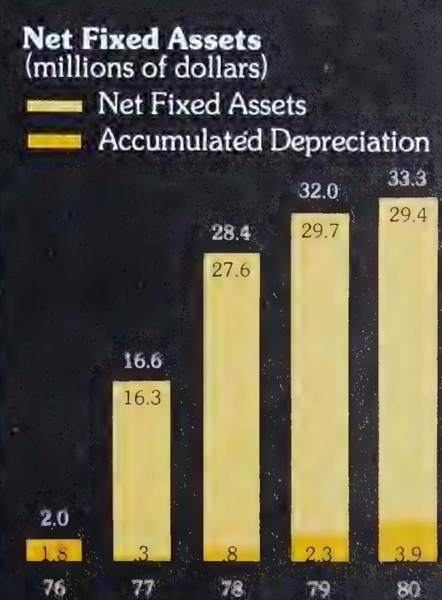
CU Resources carried on its search for oil and gas in central and northwestern Alberta and northeastern British Columbia.

During 1980, the company participated in the drilling of two oil wells, one gas well and one unsuccessful drilling venture.

At year-end, CU Resources' net land holdings were 16,000 acres. The company had net reserves of 350,000 cubic metres (2.2 million barrels) of oil and 28.4 million cubic metres (one billion cubic feet) of natural gas. Production for the year totalled 30,200 cubic metres (190,000 barrels) of oil and 3.7 million cubic metres (130 million cubic feet) of natural gas.

As a Canadian-owned exploration company, CU Resources is eligible for federal government incentives under the National Energy Program.





FINANCIAL REVIEW

EARNINGS

Earnings of $2.37 per common share in 1980 increased 6% over the $2.23 recorded in 1979 but were well below the 10% annual growth rate which has been experienced in the last five years. The average number of common shares increased to 20,818,000 from 18,741,000 in the prior year as a result of an issue of common shares in December 1979.

Earnings per common share

	1980	1979	Gain in 1980	
	$	$	$	%
Electric	1.41	1.16	0.25	22
Natural gas	0.84	0.96	(0.12)	(13)
Other	0.12	0.11	0.01	9
Total	2.37	2.23	0.14	6

The total earnings attributable to common shares of $49,273,000 were up 18% in the year, less than the 24% increase in the average common equity investment by shareholders.

From this panel at Northwestern Utilities' Control Centre in Edmonton, the operator monitors and controls the flow of natural gas throughout the company's interconnected pipeline system. Northwestern serves more than 276,000 customers in north-central Alberta.

Earnings Growth

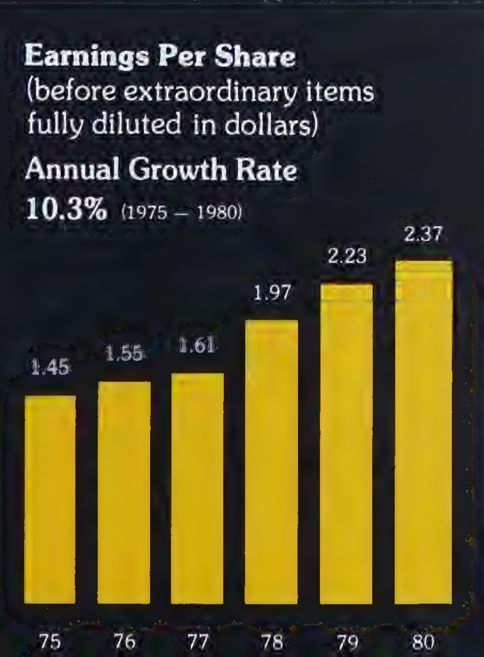
($ Millions)

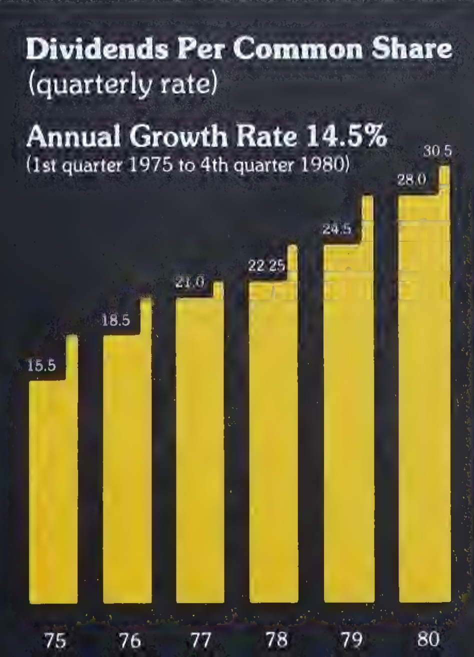
	Electric	Natural Gas	Other	Total
Five Year annual growth rate	22.3%	12.9%		19.2%
1980	$29.3	$17.6	$2.4	$49.3
1979	21.7	18.1	2.0	41.8
1978	18.7	15.7	1.2	35.6
1977	15.4	11.7	0.6	27.7
1976	12.8	11.1	0.1	24.0
1975	10.7	9.6	0.2	20.5

Growth in earnings in the year was unfavorably affected by warmer than normal temperatures and receipt of only partial relief, through regulatory decisions, from the very substantial increase experienced in 1980 in the costs of providing utility services. In total, the utility cost of service increased by $142,200,000 to $744,700,000 in the year. The 24% increase is primarily due to the increase in the government controlled cost of acquiring a natural gas supply, a new federal government excise tax on sales by the natural gas utilities and the impact of inflation and growth on the cost of labor, supplies and investment capital. Of this increase, over 90% ($129,000,000) was recovered through rates approved by decisions of regulatory boards. An additional $7,800,000 of natural gas supply costs has been deferred and will be recovered in 1981 from the rates established in 1980.

The remaining $5,400,000 represents the difference between interim rates requested and interim rates granted. Final regulatory decisions, to be received in 1981, will be required to determine the extent to which recovery of this cost will be allowed. This recovery would be an addition to earnings recorded in 1981. An amended Public Utilities Board Act of Alberta and The Gas Utilities Act of Alberta enable the regulatory board to exercise considerable flexibility in the recognition of the appropriate revenue requirements for a "test year".

As a result, 1980 records a 13% decline in earnings per share from natural gas utility operations during a year when shareholders' average equity investment has increased by 9% in this sector. Had there been no lag in receipt of interim rate relief, this decline in earnings would have been avoided, but the warm weather would still have delayed the earnings improvement associated with an increase in shareholder investment.





CAPITAL EXPENDITURES

Expenditures on new plant and equipment were, as forecast in the 1979 annual report, at a record level in 1980. Of the $267,000,000 total outlay, nearly $118,000,000 or 44% was directed to construction of the Battle River Generating Unit #5. The unit is expected to meet the scheduled cost and commissioning date upon completion in 1981.

	1980 ($ Millions)	1980 Forecast ($ Millions)	1981 Forecast ($ Millions)
Electric	190.1	194.5	145.0
Natural Gas	75.6	60.5	98.0
Other	1.3	.7	3.0
Total	267.0	255.7	246.0

Approximately $250,000,000 will be invested in new plant and equipment in 1981. The current uncertainty regarding scheduling of many of the major energy-related projects planned to take place in Alberta over the decade may result in some hesitation in housing starts and growth in customers in 1981, particularly for the gas utility subsidiaries of the company.

Forecast spending may be reduced if sponsors of the major projects are unable to proceed as planned.

FINANCING

Funds from operations, after providing for dividends to shareholders, amounted to $60,400,000 in 1980 while demands for funds to build new plant and equipment and to meet other obligations to retire debt, etc., were $296,100,000. Thus 20 cents out of every dollar of the funds required is obtained from operations of the company and new external financings were arranged to meet the balance. The reliance on new external financing can be considered normal for a group of fast-growing utilities and is a pattern that will continue into the foreseeable future.

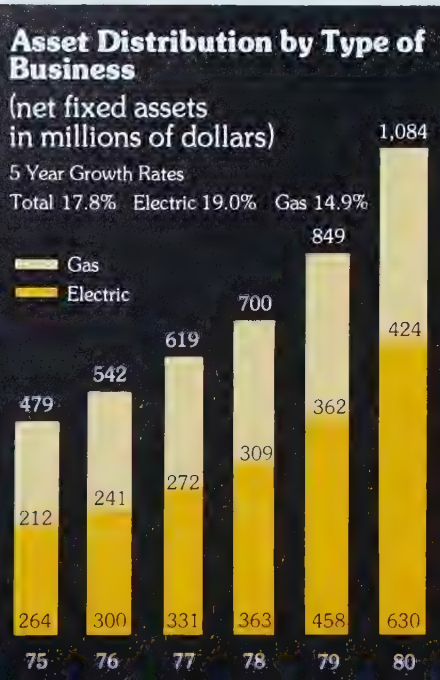
External financings of $150,000,000 were well in excess of the level previously recorded. The company completed an issue of $50,000,000 of 10.24% preferred shares in May and $100,000,000 of 12% debentures in July. Timing of these issues was fortunate as the level of interest rates climbed from that point forward in the year.

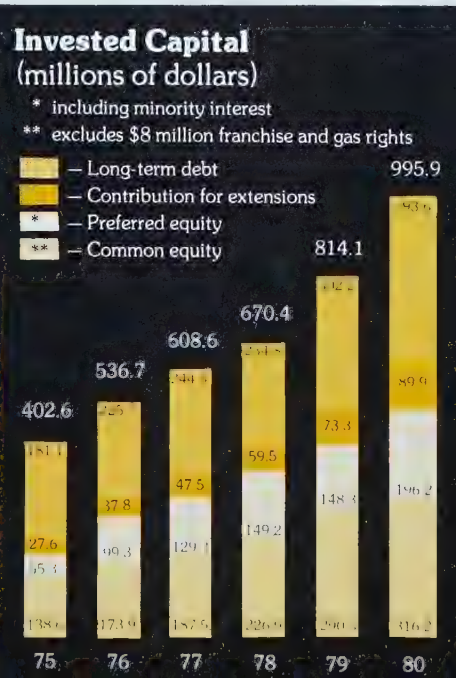
Accompanying the issue of securities were reviews by the major credit rating agencies in Canada. The senior debt securities offered by the company, the debentures, were judged as AAA (A+), making it possible for the company to minimize the costs of servicing this form of financing.

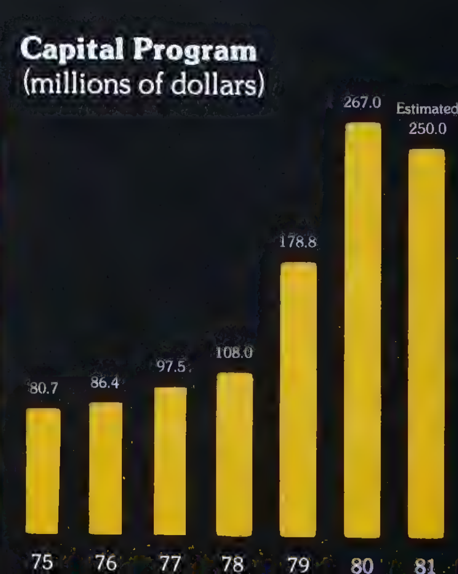
By the close of the year, the company was once again in registration for new financing — an issue of $55,000,000 of 10.12% preferred shares completed in February 1981.

DISTRIBUTION OF EARNINGS

In the fourth quarter of each year since a corporate reorganization in 1972, the company has increased the rate of dividend paid on a common share. It is the practice to distribute approximately one half of earnings to shareholders and to reinvest the balance in the growth of the company. In the fourth quarter in 1980, the dividend per common share was increased to







30½ cents from 28 cents. On an annualized basis, the common dividend is $1.22, representing 51% of the $2.37 recorded as earnings per share.

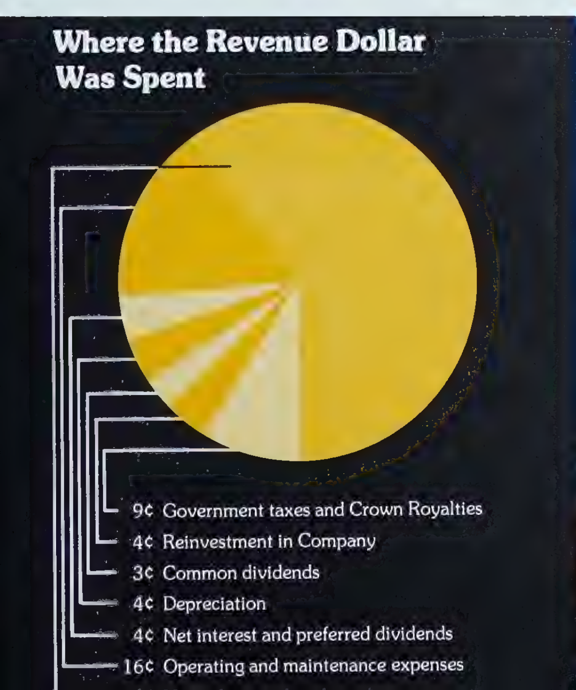
REGULATORY ACTIVITY

In the operations sections of this annual report, the regulatory activity of the past year has been described. Numerous applications were made to recover rising costs; however, the rate of return on common equity judged to be financing the utility "rate base" was last determined by orders related to the 1978 test year and ranged from 14.18% to 14.4%. Higher inflation levels since that time have increased the cost of all forms of capital. The current applications are designed to increase return on equity, as calculated in a like manner, to about 15½%. In a decision dated February 11, 1981 regarding an application by Canadian Western Natural Gas Company Limited, the Public Utilities Board of Alberta provided for a return on equity of 14¾%.

In 1980, the federal government introduced legislation that would have had the effect of increasing the utility bills paid by all Albertans. Under this proposal only 50% of income taxes paid to the federal government by the utilities would be returned to the province rather than 95%. Alberta has provided for all provincial income tax and the federal tax returned to the province to be rebated in total to customers of the tax-paying utility. This impending change forced Alberta Power to draw back from a plan which would have involved paying a higher level of taxes, a change that was beneficial to consumers because it meant more debt and less equity could be employed in financing utility growth. In 1981, after considerable protest, the proposed legislative change was withdrawn by the federal government. The company, as a result, will be reviewing its position on tax accounting.

WHERE THE REVENUE DOLLAR WAS SPENT

The distribution of the revenue pie is expected to change considerably in 1981 if there is no change in the announced National Energy Program. An 8% production tax and other changes will result in higher utility rates for natural gas utility customers as will the full-year impact of a natural gas excise tax that increased gas utility bills by about 12% late in 1980. In 1981, up to 25% of total revenues from utility customers may be required for payment of government taxes and royalties to the Crown.



Canadian Utilities headquarters are located in The Milner Building in downtown Edmonton. The company also occupies space in the adjacent Standard Life Building.

FINANCIAL STATEMENTS

CANADIAN UTILITIES LIMITED

AUDITORS' REPORT TO THE SHAREHOLDERS

We have examined the consolidated balance sheet of Canadian Utilities Limited as at December 31, 1980 and the consolidated statements of earnings, retained earnings and changes in financial position for the year then ended. Our examination was made in accordance with generally accepted auditing standards and, accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the company as at December 31, 1980 and the results of its operations and the changes in its financial position for the year then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

Peat, Marwick, Mitchell & Co.

Edmonton, Canada
January 30, 1981

Chartered Accountants

Canadian Western's Carbon field is now used as storage facility to hold quantities of gas that can be called upon to meet peaking requirements.

CONSOLIDATED STATEMENT OF EARNINGS

Year ended December 31, 1980 with comparative figures for 1979

	1980	1979
	(Thousands)	
Revenues	**$757,696**	$625,728
Operating Expenses		
Natural gas supply (Note 2)	**425,618**	342,265
Operating and maintenance	**166,284**	139,162
Taxes — other than income	**33,374**	27,980
Depreciation	**29,485**	26,520
	654,761	535,927
	102,935	89,801
Allowance for Funds Used During Construction	**19,653**	7,104
Other Income	**2,660**	1,502
	125,248	98,407
Interest Expense	**39,496**	27,364
	85,752	71,043
Income Taxes (Note 3)	**21,584**	17,559
	64,168	53,484
Minority Interests	**2,555**	2,296
Net Earnings	**61,613**	51,188
Preferred Dividend Requirements	**12,340**	9,379
Balance Attributable to Common Shares	**$ 49,273**	$ 41,809
Earnings — Dollars Per Common Share	**$ 2.37**	$ 2.23

See accompanying summary of significant accounting policies and notes to consolidated financial statements.

CONSOLIDATED BALANCE SHEET

December 31, 1980 with comparative figures for 1979

			1980	1979
			(Thousands)	
ASSETS				
Current Assets				
Cash and short-term deposits			**$ 2,565**	$ 1,278
Accounts receivable (Note 4)			**171,342**	112,101
Materials and supplies — at average cost			**16,941**	15,942
Natural gas stored — at cost			**1,894**	286
			192,742	129,607
Trust Assets Held for Rural Electrification Associations, Per Contra			**13,379**	12,408
Trust Assets Held for Income Tax Rebate for Consumers, Per Contra			**4,559**	9,052
Property, Plant and Equipment Less Accumulated Depreciation (Note 5)			**1,083,681**	849,406
Deferred Expenses (Note 6)			**37,665**	21,606
			$1,332,026	$1,022,079
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current Liabilities				
Due to bank			**$ 25,308**	$ 13,118
Accounts payable and accrued liabilities			**166,319**	113,565
Income and other taxes			**24,854**	4,711
Dividends payable			**2,883**	2,923
Long-term debt — current maturities (Note 8)			**3,556**	1,028
Note payable to affiliated company				150
Deposits			**2,314**	2,084
			225,234	137,579
Amounts Held in Trust, Per Contra			**17,938**	21,460
Notes Payable (Note 7)			**60,000**	27,000
Long-Term Debt (Note 8)			**393,611**	302,225
Contributions for Extensions to Plant			**89,944**	73,286
Deferred Income Taxes (Note 3)			**4,284**	2,522
Other Liabilities (Note 9)			**20,558**	11,383
Minority Interests (Note 10)			**40,008**	40,008
Shareholders' Equity				
Preferred shares (Note 11)			**156,225**	108,282
	1980	1979		
Common shares (Note 12)	**$199,275**	$199,275		
Retained earnings (Note 8)	**124,949**	99,059		
			324,224	298,334
			480,449	406,616
			$1,332,026	$1,022,079

On behalf of the Board:

J. E. Maybin/Director **D. R. B. McArthur**/Director

See accompanying summary of significant accounting policies and notes to consolidated financial statements.

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

Year ended December 31, 1980 with comparative figures for 1979

	1980	1979
	(Thousands)	
Balance at Beginning of Year	**$ 99,059**	$ 74,322
Add		
Net earnings	**61,613**	51,188
Adjustment for deferral of preferred share issue expense less related income taxes		2,548
	160,672	128,058
Deduct		
Dividends		
Preferred shares	**11,887**	9,375
Common shares	**23,836**	18,905
	35,723	28,280
Share issue expense less related income taxes		719
	35,723	28,999
Balance at End of Year	**$124,949**	$ 99,059

See accompanying summary of significant accounting policies and notes to consolidated financial statements.

CONSOLIDATED STATEMENT OF CHANGES IN FINANCIAL POSITION

Year ended December 31, 1980 with comparative figures for 1979

	1980	1979
	(Thousands)	
Sources of Working Capital		
Net earnings	**$ 61,613**	$ 51,188
Add non-cash items, principally depreciation	**34,497**	29,218
Provided from operations	**96,110**	80,406
Increase in notes payable	**33,000**	27,000
Issue of long-term debt	**100,000**	75,000
Issue of preferred shares	**50,000**	
Issue of common shares		37,943
Contributions for extensions to plant	**19,060**	15,614
Disposition of property, plant and equipment	**496**	1,146
Other	**8,586**	3,110
	307,252	240,219
Uses of Working Capital		
Purchase of property, plant and equipment	**266,984**	178,775
Reduction in long-term debt	**8,614**	6,493
Dividends — preferred	**11,887**	9,375
— common	**23,836**	18,905
Preferred shares purchased for cancellation	**2,057**	900
Increase in deferred expenses	**18,394**	7,239
	331,772	221,687
Increase (Decrease) in Working Capital	**$ (24,520)**	$ 18,532

See accompanying summary of significant accounting policies and notes to consolidated financial statements.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

December 31, 1980

The company is a holding company. Its principal subsidiaries are engaged in the generation, transmission, distribution and sale of electric energy and in the production, purchase, distribution and sale of natural gas.

Matters such as rates, construction, operation and accounting in connection with the utility subsidiaries are subject to the jurisdiction of certain regulatory bodies. Utility rates are determined primarily by the Public Utilities Board of Alberta based on rate base, rate of return and cost of service.

Basis of consolidation

The consolidated financial statements include the accounts of the company and all subsidiary companies. All material inter-company balances and transactions have been eliminated.

Property, plant and equipment

Property, plant and equipment includes cost of land, resource properties, buildings and equipment. The gross cost of additions includes an allowance for funds used during construction based on the debt and equity cost of capital components. Certain additions are made with assistance of cash contributions where the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. These contributions are amortized on the same basis as the assets to which they relate.

Depreciation is provided on classes of assets at various rates on a straight line basis over the estimated useful lives of the assets. In accordance with the orders of regulatory bodies, depreciation is provided after giving effect to contributions for extensions to plant. The major assets are depreciated at rates varying from 2.113% to 6.6%. Certain resource properties are depreciated in part on a unit withdrawal basis.

On retirement of depreciable plant, the accumulated depreciation is charged with the cost of the retirement unit less net salvage. Gains and losses on extraordinary retirements are recognized as extraordinary items in the financial statements.

Deferred expenses

Deferred charges relating to gas exploration include expenditures related to the development of gas reserves. Costs resulting in a successful venture are capitalized and depreciated on a unit withdrawal basis.

Prepaid natural gas supply expense is the portion of gas supply expense that will be recovered in revenues in the following year.

Expenses of issue of long-term debt are amortized over the periods that the debt is outstanding and expenses of issue of preferred shares are amortized from the date of issue over the lesser of the expected life of the issue or 30 years.

Goodwill consists of the excess cost of shares issued over the underlying net book value of shares acquired in 1972 from minority shareholders of a subsidiary company and is being amortized over a period of 40 years.

Other deferred charges are subject to amortization over varying periods of time not exceeding 40 years.

Income taxes

In fixing rates, except for the matters referred to in the following paragraph, the utility subsidiaries recover only taxes payable currently. Capital cost allowances are claimed on depreciable assets included in the rate base of the utility companies and, accordingly, to the extent that capital cost allowances claimed are in excess of recorded depreciation, there has been a related reduction in the amount of income taxes otherwise payable which has not been reflected in the consolidated financial statements. The reduction will become a charge to be borne by the consumer in future years when recorded depreciation exceeds capital cost allowances claimed for income tax purposes.

The utility subsidiaries are permitted to claim deferred income taxes with respect to acquisition of natural gas rights, deferred gas costs, rate case expenses and share issue costs.

Natural gas supply

The Province of Alberta enacted The Natural Gas Rebates Act effective January 1, 1974 to shelter the majority of Alberta natural gas consumers from the full impact of significant price increases for natural gas. Under the provisions of the Act, the gas subsidiaries are reimbursed for the excess price paid to their suppliers over the support price. The consolidated statement of earnings is charged with the net cost of natural gas.

Equipment Leases

The regulatory process in Alberta requires that application be made for the capitalization of leases in the determination of consumer rates. The company will seek approval of the Public Utilities Board of Alberta to capitalize leases in accordance with generally accepted accounting principles. Prior to such approval, leases that would otherwise be treated as capital leases are accounted for as operating leases.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 1980

1. Incorporation

The company was incorporated under the laws of Canada by letters patent dated May 18, 1927 and was continued under the Canada Business Corporations Act on August 15, 1979.

2. Natural gas supply expense

The natural gas supply expense is net of Alberta government rebate amounting to $117,760,000 in 1980 ($109,007,000 in 1979). It also includes the newly imposed federal excise tax of $19,786,000 in 1980.

3. Income taxes

The provision for income taxes in the consolidated statement of earnings includes a provision for deferred taxes of $5,771,000 in 1980 ($1,525,000 in 1979). The cumulative amount of recorded deferred taxes to December 31, 1980 is $8,407,000, of which $4,284,000 is recorded as a deferred credit, $293,000 as a reduction in deferred expenses and $3,830,000 is included in income and other taxes payable.

As described in the Summary of Significant Accounting Policies, income taxes otherwise payable have been reduced by claiming capital cost allowances in excess of recorded depreciation. Had this practice not been followed, income taxes payable would have increased in the approximate amount of $18,832,000 in 1980 ($14,114,000 in 1979), and to an accumulated amount of $109,335,000 at December 31, 1980. As the company's rates are determined on a taxes payable basis and all such deferred taxes will be included in rates in the future, the company has not recorded any liability relating to these deferred taxes.

4. Accounts receivable

	1980	1979
	(Thousands)	
Consumer accounts, gas and electric	**$106,470**	$ 67,742
Receivable from the Province of Alberta	**33,921**	26,759
Other receivables and deposits	**30,951**	17,600
	$171,342	$112,101

5. Property, plant and equipment

	1980		1979	
	Cost	**Accumulated Depreciation and Depletion**	Cost	Accumulated Depreciation and Depletion
	(Thousands)		(Thousands)	
Natural gas utility plant and equipment	**$ 543,842**	**$129,736**	$ 470,142	$117,711
Electric utility plant and equipment	**735,052**	**106,741**	545,742	89,886
Other plant and equipment	**33,122**	**3,931**	32,006	2,321
Undertakings, franchise and gas rights	**8,000**		8,000	
Land	**4,073**		3,434	
	$1,324,089	**$240,408**	$1,059,324	$209,918
	$1,083,681		$849,406	

6. Deferred expenses

	1980	1979
	(Thousands)	
Gas exploration	**$16,439**	$10,157
Debt and preferred share issue expense	**9,845**	7,501
Natural gas supply expense	**7,832**	
Goodwill	**446**	461
Other	**3,103**	3,487
	$37,665	$21,606

7. Notes payable

The company has arranged a bank loan agreement to provide up to $50,000,000 to March 14, 1982. The company issues commercial paper and assumes bank loans relying upon these commitments. The company will at all times segregate sufficient unused lines of credit to make payment of not less than 50% of the short-term promissory notes outstanding. At December 31, 1980 the company had notes payable of $60,000,000 ($27,000,000 at December 31, 1979) at interest rates varying from 13.90% to 18.25% with maturities to March 14, 1982.

8. Long-term debt

	1980	1979
	(Thousands)	
Canadian Utilities Limited		
Sinking fund debentures 8⅜% to 12% due to 2002	**$310,088**	$213,120
Alberta Power Limited		
First mortgage sinking fund bonds 4⅛% to 6½% due to 1992	**27,688**	27,697
Sinking fund debentures 7¼% to 9⅝% due to 1991	**19,568**	20,261
Northwestern Utilities Limited		
First mortgage sinking fund bonds 5⅜% to 9¾% due to 1994	**17,966**	18,805
Sinking fund debentures 7¼% due 1985	**2,494**	2,600
Canadian Western Natural Gas Company Limited		
First mortgage sinking fund bonds 5⅜% to 7% due to 1992	**12,609**	13,437
Sinking fund debentures 9¾% due 1990	**6,754**	7,333
Total long-term debt	**397,167**	303,253
Deduct current maturities	**3,556**	1,028
Long-term debt less current maturities	**$393,611**	$302,225

The long-term debt outstanding and current maturities thereof have been reduced by bonds and debentures purchased for future sinking fund payments. Such payments exclude requirements which may be satisfied by certification of property additions.

Annual sinking fund requirements for each of the following years are:

	(Thousands)
1981	$ 3,556
1982	10,092
1983	14,151
1984	10,198
1985	15,987

The bond and debenture indentures executed by the company and its subsidiaries place limitations on the company and its subsidiaries, including restrictions on the payment of dividends. Of the consolidated retained earnings at December 31, 1980, approximately $75,332,000 were free from such restrictions.

9. Other liabilities

As Alberta gas producers, the gas subsidiaries receive a pro rata share of monies available under The Natural Gas Price Administration Act. These monies, net of royalties and income taxes, have been included in other liabilities and amount to $16,554,000 ($8,270,000 in 1979). It is the company's intention, subject to the approval of the Public Utilities Board of Alberta, to charge the costs of unsuccessful exploration against this amount.

10. Minority interests

	1980	1979
	(Thousands)	
Minority interest in the preferred shares of subsidiaries:		
Northwestern Utilities Limited		
105,000 4% Cumulative Redeemable Preference Shares with a stated value of $100 each	**$10,500**	$10,500
Canadian Western Natural Gas Company Limited		
275,410 4% Cumulative Redeemable Preference Shares of the par value of $20 each	**5,508**	5,508
200,000 5½% Cumulative Redeemable Preference Shares of the par value of $20 each	**4,000**	4,000
CU Ethane Limited		
800,000 Floating Rate Cumulative Redeemable Preferred Shares Series A of the par value of $25 each The rate of dividend is one-half of the average prime bank rate of two chartered banks plus 1¼% The company is obligated to redeem 80,000 shares per year at par commencing in 1989	**20,000**	20,000
	$40,008	$40,008

11. Preferred shares

Authorized:

40,000 5% Cumulative Redeemable Preferred Shares.

150,000 Series Preferred Shares, issuable in series, of which 15,000 shares have been designated as Cumulative Redeemable Preferred Shares, 4¼% Series and 50,000 shares have been designated as Cumulative Redeemable Preferred Shares, 6% Series.

An unlimited number of Series Second Preferred Shares, issuable in series, of which the following have been designated as Cumulative Redeemable Second Preferred Shares.

		Number
Series A	10¼%	1,152,000
Series B	9.24%	1,552,000
Series C	7.30%	1,124,980
Series D	10.24%	2,000,000

Issued:

	Stated Value	Redemption Premium	Reducing To	1980 Number	1980 Value (Thousands)	1979 Number	1979 Value (Thousands)
5% preferred shares	$100	4%		**40,000**	**$ 4,000**	40,000	$ 4,000
Preferred shares 4¼% Series	$100	2½%		**15,000**	**1,500**	15,000	1,500
Preferred shares 6% Series	$100	3%	1%	**50,000**	**5,000**	50,000	5,000
10¼% second preferred Series A	$ 25	5%	Nil	**1,152,000**	**28,800**	1,152,000	28,800
9.24% second preferred Series B	$ 25	5%	Nil	**1,552,000**	**38,800**	1,600,000	40,000
7.30% second preferred Series C	$ 25	4%	Nil	**1,124,980**	**28,125**	1,159,280	28,982
10.24% second preferred Series D	$ 25	4%	Nil	**2,000,000**	**50,000**		
					$156,225		$108,282

During the year the company issued $50,000,000 Series D Second Preferred Shares for cash. These shares are retractable at the option of the holder for redemption on June 1, 1985 and June 1, 1990 at $25 per share plus dividends accrued and unpaid.

The preferred shares may be redeemed at the option of the company subject to premiums listed plus dividends accrued and unpaid.

The company is required in each year to make all reasonable efforts to purchase for cancellation the number of shares of each series listed below at a price not exceeding $25 per share plus costs of purchase. If after all reasonable efforts the company is unable to do so, the company's obligation to purchase shares in such year is extinguished. Special provisions apply to the 10.24% series which increase the company's commitment after June 30, 1985.

		Number
Series A	10¼%	48,000
Series B	9.24%	48,000
Series C	7.30%	36,000
Series D	10.24%	40,000

During the year ended December 31, 1980 the company purchased 34,300 of the 7.30% series and 48,000 of the 9.24% series, thereby reducing the capital of the company by $2,057,500 (1979 — 36,000 of the 7.30% series reducing the capital of the company by $900,000).

12. Common shares

Authorized:

An unlimited number of shares without nominal or par value.

Issued:

	1980 Number	1980 Value (Thousands)	1979 Number	1979 Value (Thousands)
Balance at beginning of year	**20,817,623**	**$199,275**	18,625,868	$160,613
Issued under employee share purchase plan			91,755	1,125
Issued during the year for cash			2,100,000	37,537
Balance at end of year	**20,817,623**	**$199,275**	20,817,623	$199,275

At December 31, 1980 the company had reserved 174,717 unissued common shares for issuance under the employee share purchase plan. The rights to purchase are exercisable for $16.36 per share on December 31, 1981.

13. Commitments and contingencies

The cost of the company's planned construction and expansion program for 1981 will amount to approximately $250,000,000 of which $73,000,000 was under contract at December 31, 1980. Total commitments under contract for 1981 and future years were approximately $168,000,000.

Minimum yearly equipment lease payments are $8,450,000, $10,075,000, $10,167,000, $9,964,000, $10,121,000 for the years 1981-1985 respectively. Leases range in length from three to 15 years.

The company has a pension plan covering substantially all its employees. The aggregate unfunded past service liability amounted to approximately $9,918,000 at December 31, 1980. Of this amount $2,124,000 must be funded by December 31, 1981 and the balance over a period not exceeding 13 years.

14. Segmented information

Financial information relating to segments of the company's business is presented below:

Operating segments	**Electric**		**Natural Gas**		**Other**		***Consolidated**	
(Thousands)	**1980**	1979	**1980**	1979	**1980**	1979	**1980**	1979
Revenues								
Outside customers	**$149,847**	$124,647	**$581,677**	$477,929	**$26,172**	$23,152	**$ 757,696**	$ 625,728
Inter-segment	**411**	244	**16,394**	13,905	**109**	38		
	150,258	124,891	**598,071**	491,834	**26,281**	23,190	**757,696**	625,728
Operating expenses								
Operating	**79,985**	66,434	**542,536**	440,708	**19,669**	16,452	**625,276**	509,407
Depreciation	**15,958**	14,667	**11,904**	10,305	**1,623**	1,548	**29,485**	26,520
	95,943	81,101	**554,440**	451,013	**21,292**	18,000	**654,761**	535,927
Segment operating income	**54,315**	43,790	**43,631**	40,821	**4,989**	5,190	**102,935**	89,801
Income deductions	**3,899**	9,143	**15,412**	10,411	**427**	1,500	**19,738**	21,054
Income taxes	**11,810**	6,657	**7,623**	9,240	**2,151**	1,662	**21,584**	17,559
Net earnings	**38,606**	27,990	**20,596**	21,170	**2,411**	2,028	**61,613**	51,188
Preferred dividend requirements	**9,295**	6,292	**3,045**	3,087			**12,340**	9,379
Balance attributable to common shares	**$ 29,311**	$ 21,698	**$ 17,551**	$ 18,083	**$ 2,411**	$ 2,028	**$ 49,273**	$ 41,809
Total assets	**$691,250**	$508,896	**$604,014**	$478,157	**$43,364**	$41,328	**$1,332,026**	$1,022,079
Capital expenditures	**$190,148**	$110,714	**$ 75,546**	$ 64,451	**$ 1,290**	$ 3,610	**$ 266,984**	$ 178,775

* Inter-segment transactions have been eliminated in the consolidated column.

15. Comparative figures

Certain of the 1979 comparative figures have been reclassified to conform with the financial statement presentation adopted for 1980.

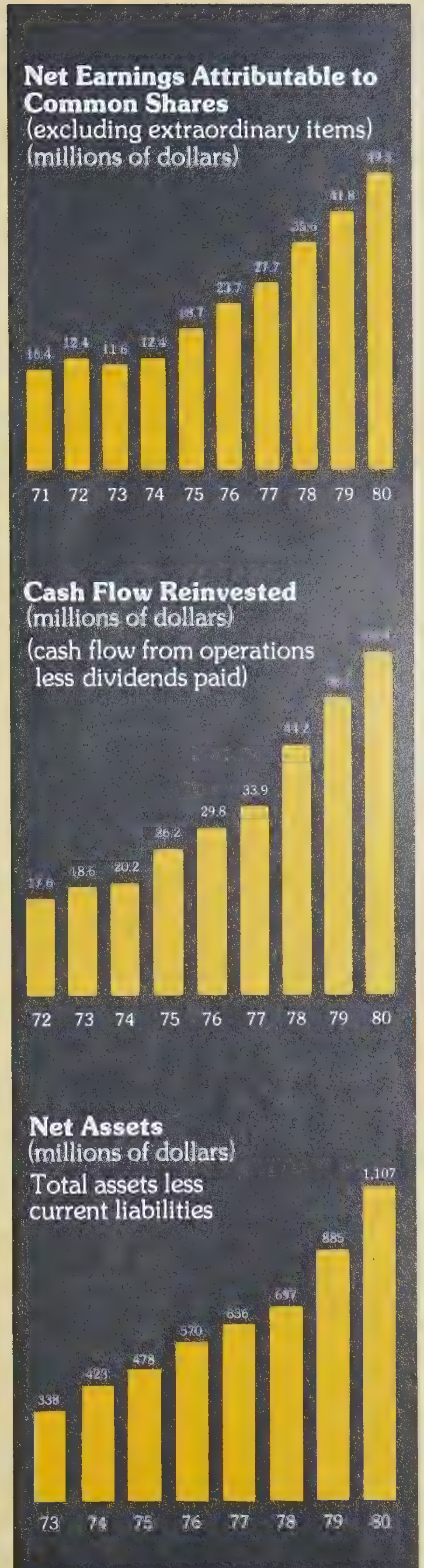
CONSOLIDATED TEN-YEAR FINANCIAL SUMMARY

(Dollars in millions, except as indicated)	**1980**	1979	1978	1977
Operating Revenues				
Natural gas	**581.7**	477.9	431.8	318.7
Electric	**149.8**	124.6	114.7	93.9
Other	**26.2**	23.2	7.7	2.8
	757.7	625.7	544.2	415.4
Operating Expenses				
Natural gas supply	**425.6**	342.3	315.5	221.3
Operating and maintenance	**166.3**	139.1	107.2	87.2
Taxes — other than income	**33.4**	28.0	26.6	21.8
Depreciation	**29.5**	26.5	23.2	18.8
	654.8	535.9	472.5	349.1
	102.9	89.8	81.7	66.3
Allowance for Funds Used During Construction	**19.7**	7.1	4.7	2.3
Other Income	**2.7**	1.5	2.5	1.4
	125.3	98.4	88.9	70.0
Interest Expense	**39.5**	27.4	22.4	21.4
	85.8	71.0	66.5	48.6
Income Taxes	**21.6**	17.5	20.0	12.5
	64.2	53.5	46.5	36.1
Minority Interests	**2.6**	2.3	1.5	.9
Net Earnings before Extraordinary Items	**61.6**	51.2	45.0	35.2
Extraordinary Items — Non-Recurring Gain (Loss)				(1.6)
Net Earnings	**61.6**	51.2	45.0	33.6
Preferred Dividend Requirements	**12.3**	9.4	9.4	7.5
Balance Attributable to Common Shares	**49.3**	41.8	35.6	26.1
Contribution by Operating Segment*				
Before Extraordinary Items				
Electric	**29.3**	21.7	18.7	15.4
Natural gas	**17.6**	18.1	15.7	11.7
Other	**2.4**	2.0	1.2	.6
	49.3	41.8	35.6	27.7
Common Shares Outstanding (thousands)				
End of year	**20,818**	20,818	18,626	17,122
Average for year — fully diluted	**20,992**	18,783	18,146	17,312
Earnings — Dollars Per Fully Diluted Common Share				
Net earnings before extraordinary items	**2.37**	2.23	1.97	1.61
Net earnings after extraordinary items	**2.37**	2.23	1.97	1.52
Common Dividends Paid*				
Dividends per share (dollars)	**1.145**	1.015	.9125	.8525
Total dividends paid	**23.8**	18.9	16.4	14.4
Payout Ratio*				
Dividends paid ÷ earnings available	**48.3%**	45.2%	45.9%	55.2%
Common Shareholders' Equity Dollars Per Share*				
At year-end — fully diluted	**15.21**	14.00	12.22	11.06
Rate of Return on Common Shareholders' Equity*				
Before extraordinary items	**15.6%**	15.9%	16.1%	14.6%
After extraordinary items	**15.6%**	15.9%	16.1%	13.7%
Stock Market Record of Common Shares* (dollars)				
High	**27**	21	18	15-1/2
Low	**18-1/4**	16	14-1/8	12-5/8
Close	**22-3/4**	19	16-1/8	15-1/2
Gross Fixed Assets	**1,324.1**	1059.3	883.9	780.5
Net Fixed Assets	**1,083.7**	849.4	700.1	618.8
Total Assets	**1,332.0**	1,022.1	843.7	744.3
Capitalization*				
Long-term debt	**393.6**	302.2	233.7	244.3
Contributions	**89.9**	73.3	59.5	47.5
Preferred shares	**196.2**	148.3	149.2	129.3
Common equity	**316.2**	290.3	226.9	187.5
Total capitalization	**995.9**	814.1	670.4	608.6
Capitalization Ratio*				
Long-term debt	**39%**	37%	35%	40%
Contributions	**9%**	9%	9%	8%
Preferred shares	**20%**	18%	22%	21%
Common equity	**32%**	36%	34%	31%
Times Debt Interest Earned (pretax)*	**3.17**	3.60	3.97	3.26

*Not applicable prior to 1972 corporate reorganization.

Note: Comparative figures for years prior to 1972 have been reclassified to conform with financial presentation following corporate reorganization in 1972.

1976	1975	1974	1973	1972	1971	1970
216.5	141.8	91.2	82.0	78.9	70.3	62.9
78.1	57.9	46.3	38.3	33.8	30.6	27.7
1.3	.7	.3	.1			
295.9	200.4	137.8	120.4	112.7	100.9	90.6
134.8	70.9	40.2	36.0	32.4	27.0	22.6
72.8	56.5	43.6	34.7	33.4	29.1	26.4
17.0	11.8	8.0	6.8	6.5	6.0	5.3
15.6	13.3	12.9	11.0	10.1	9.7	9.4
240.2	152.5	104.7	88.5	82.4	71.8	63.7
55.7	47.9	33.1	31.9	30.3	29.1	26.9
1.3	4.0	1.6	.8	2.2	.8	.2
2.3	1.4	1.0	.8	.8	1.3	.7
59.3	53.3	35.7	33.5	33.3	31.2	27.8
22.3	19.9	17.2	13.7	12.2	9.9	9.1
37.0	33.4	18.5	19.8	21.1	21.3	18.7
8.6	8.7	2.4	4.5	5.0	7.2	6.9
28.4	24.7	16.1	15.3	16.1	14.1	11.8
.9	.9	.9	.9	1.0	1.2	1.2
27.5	23.8	15.2	14.4	15.1	12.9	10.6
	2.4	.5		(.1)	.2	.2
27.5	26.2	15.7	14.4	15.0	13.1	10.8
3.8	5.1	2.8	2.8	2.7	2.5	2.5
23.7	21.1	12.9	11.6	12.3	10.6	8.3
12.8	10.7	7.2	6.8	9.1		
10.8	7.9	5.2	4.8	3.3		
.1	.1					
23.7	18.7	12.4	11.6	12.4		
6,634	14,198	10,075	10,065	10,063	10,056	8,949
5,567	14,258	14,216	14,216	14,216	9,503	8,912
1.55	1.45	1.05	.99	1.05	.91	.80
1.55	1.61	1.08	.99	1.04	.93	.82
.765	.65	.59	.55	.52		
11.0	7.1	5.9	5.5	5.2		
46.4%	33.6%	45.7%	47.4%	42.3%		
10.36	9.41	8.49	8.04	7.61		
14.9%	15.4%	12.4%	12.3%	13.8%		
14.9%	17.1%	12.7%	12.3%	13.7%		
14-3/8	9-7/8	11	13-3/4	14-5/8		
9-1/2	7-5/8	6-1/2	8-5/8	9-1/4		
14-3/8	9-3/4	7-1/4	9-1/4	13-1/2		
688.6	613.6	538.7	470.3	435.8	397.2	359.4
542.3	478.6	413.5	355.8	330.2	300.0	270.8
644.3	573.9	475.5	391.1	363.1	328.4	306.9
225.7	181.1	194.5	167.5	156.0		
37.8	27.6	18.1	14.4	12.7		
99.3	55.3	30.5	30.5	30.5		
173.9	138.6	115.3	108.9	102.8		
536.7	402.6	358.4	321.3	302.0		
42%	45%	54%	52%	52%		
7%	7%	5%	5%	4%		
19%	14%	9%	9%	10%		
32%	34%	32%	34%	34%		
2.66	2.68	2.08	2.45	2.32		

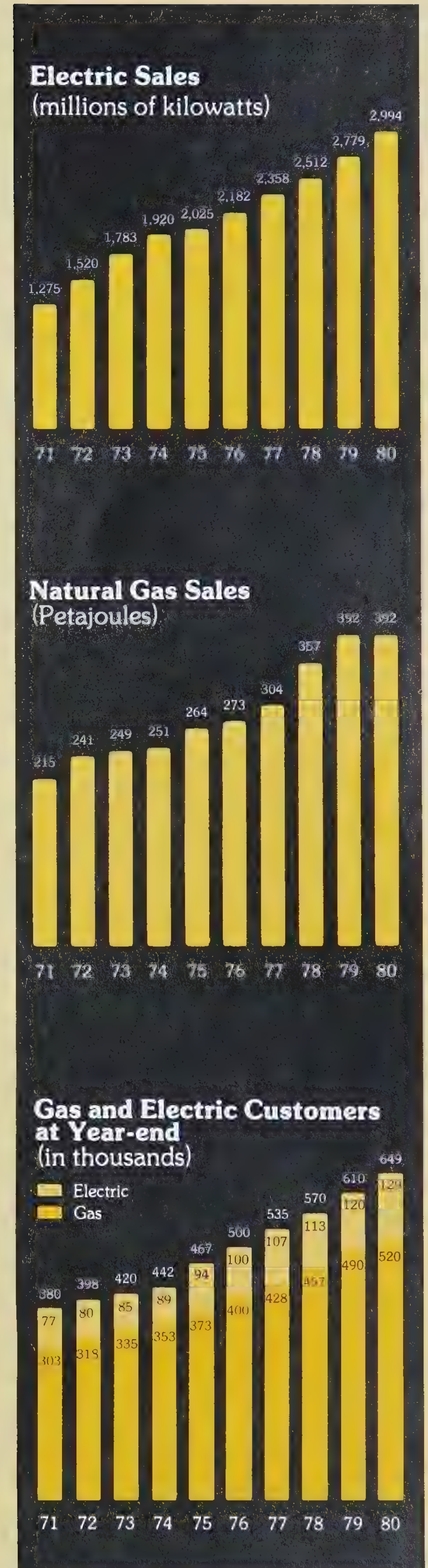


TEN-YEAR OPERATING SUMMARY

(Dollars in millions, except as indicated)

	1980	1979	1978	1977
Electric Operations				
Construction work in progress	**243.8**	107.7	31.5	34.4
Fixed assets in service	**493.2**	439.8	407.2	358.6
Gross fixed assets at cost	**737.0**	547.5	438.7	393.0
Accumulated depreciation	**106.7**	89.9	75.4	62.2
Net fixed assets	**630.3**	457.6	363.3	330.8
% growth over prior year	**38%**	26%	10%	10%
Capital additions in the year	**190.1**	110.7	48.1	44.1
Sales (millions of kilowatt hours)	**2,994**	2,779	2,512	2,358
% growth over prior years	**8%**	11%	7%	8%
Average annual use per residential customer (kWh)	**7,073**	7,162	7,058	6,764
Average annual billing per residential customer ($)	**405**	366	358	310
Maximum hourly demand (thousands of kilowatts)	**607**	573	520	524
Generating capacity (thousands of kilowatts)	**670**	668	668	671
Customers at year-end (thousands)	**128.8**	120.1	112.5	106.9
Number of communities served	**395**	392	387	385
Power lines (thousands of kilometres)	**23.7**	23.0	22.3	20.8
Gas Operations				
Gross fixed assets at cost	**553.9**	479.8	416.8	370.9
Accumulated depreciation	**129.7**	117.7	107.6	99.3
Net fixed assets	**424.2**	362.1	309.2	271.6
% growth over prior year	**17%**	17%	14%	13%
Capital additions in the year	**75.6**	64.5	48.2	38.8
Sales (billions of cubic feet)	**372**	371	339	288
% growth over prior year	**Nil**	9%	18%	12%
Average annual use per residential customer (Mcf)	**180**	196	191	180
Average annual billing per residential customer ($)	**336**	308	299	241
Maximum daily demand (thousands of cubic feet)	**1,945**	1,899	1,876	1,594
Degree days — Edmonton	**5,396**	5,636	5,530	5,124
— Calgary	**5,082**	5,366	5,592	5,289
Customers at year-end (thousands)	**520.0**	489.8	457.4	428.4
Number of communities served	**269**	272	265	260
Pipelines (thousands of kilometres)	**27.9**	27.1	25.0	23.1
Other operations				
Gross fixed assets at cost	**33.3**	32.0	28.4	16.6
Accumulated depreciation	**3.9**	2.3	.8	.3
Net fixed assets	**29.4**	29.7	27.6	16.3
Total Number of Employees	**4,144**	3,870	3,592	3,367

1976	1975	1974	1973	1972	1971	1970
20.0	14.3	42.9	11.7	38.9	26.9	4.5
332.7	295.0	217.8	206.5	159.3	148.6	143.0
352.7	309.3	260.7	218.2	198.2	175.5	147.5
53.2	45.7	41.2	36.0	31.8	28.3	24.6
299.5	263.6	219.5	182.2	166.4	147.2	122.9
14%	20%	20%	9%	13%	20%	11%
45.9	51.1	44.8	21.3	24.5	29.1	16.4
2,182	2,025	1,920	1,783	1,520	1,275	1,118
8%	5%	8%	17%	19%	14%	16%
6,773	6,673	6,251	5,954	5,704	5,451	5,209
281	223	187	169	162	158	152
455	445	388	376	342	295	281
686	686	523	512	370	367	367
99.6	94.0	88.8	84.6	80.5	77.2	74.2
368	365	364	365	365	359	355
20.1	19.3	18.8	18.1	17.4	16.0	15.6
333.9	300.8	275.5	251.7	236.9	221.2	211.3
93.0	89.3	83.9	78.6	73.8	68.9	64.0
240.9	211.5	191.6	173.1	163.1	152.3	147.3
14%	10%	11%	6%	7%	3%	5%
39.4	29.5	25.7	17.1	16.5	10.6	11.8
258	250	238	236	229	203	184
3%	5%	1%	3%	13%	10%	8%
185	212	208	212	230	218	217
190	156	115	113	120	114	108
1,430	1,318	1,228	1,109	1,132	1,115	969
4,891	5,555	5,492	5,538	6,028	5,737	5,899
4,885	5,750	5,230	5,428	5,973	5,532	5,579
400.5	373.3	353.3	335.5	317.8	303.3	289.5
257	253	253	253	251	249	240
21.8	19.5	16.7	15.8	15.2	14.8	14.1
2.0	1.0	1.0				
.2	.1					
1.8	.9	1.0				
3,161	3,133	2,933	2,746	2,576	2,298	2,255



The Early Beginnings

The Canadian Utilities energy story was just a dream when Alberta became a province in 1905. It was a dream in the mind of Eugene Coste, a consulting geologist with the Canadian Pacific Railway, looking for natural gas in the Bow Island field of southern Alberta, and in the mind of W. R. "Frosty" Martin, a driller who had acquired his trade in Pennsylvania and Ontario.

Four years after the province was founded, on a February day in 1909, Coste and Martin brought in "Old Glory" and the dream began to evolve into reality. Old Glory yielded 8.5 million cubic feet of natural gas per day, making it the largest gas well in Western Canada at that time, and putting Alberta on the energy map.

It was largely due to the efforts of Eugene Coste that Canada's two oldest natural gas companies were founded. One in Ontario, Union Gas company of Canada Limited; and the other, now known as Canadian Western Natural Gas Company Limited, in Alberta.

Calgary, then North to Edmonton

The success of the discovery well in the Bow Island field convinced Eugene Coste that it might be big enough to supply Lethbridge, Calgary, and most of southern Alberta. By August of 1910, 13 wells had been brought in with a total open flow of approximately 160 million cubic feet per day. It was on the strength of these discoveries that steps were taken towards incorporation of the company on July 19, 1911.

During the next year the company built a 170-mile, 16-inch transmission line from the Bow Island field to Lethbridge and Calgary, with connections to other communities.

Meanwhile, an Edmonton group of businessmen began working towards bringing natural gas service to the capital city, and in 1923, Northwestern Utilities Limited was formed. In 88 working days, Northwestern completed a $4 million pipeline project from Viking. On November 9, 1923, Mayor D. M. Duggan performed the ceremonial turn-on which heralded the arrival of the clean blue flame of natural gas to Edmonton.

Electric Side of the Story

Natural gas is one side of the Canadian Utilities energy story. The other is electric power, which began to unfold in the late twenties. A company called Mid-West Utilities Limited took over the operation of a number of small power plants in east-central Alberta, beginning in the town of Vegreville, and in Saskatchewan. The company name was changed to Canadian Utilities Limited in 1928.

Canadian Utilities moved ahead towards an integrated grid system supplied by major power plants in key locations. One of the first lines for the system was built in 1928, reaching to the town of Lloydminster.

The year 1928 also saw the acquisition of the plant and distribution system at Grande Prairie, as well as the Union Power Company Limited at Drumheller. From Drumheller, the power company launched an aggressive program of expansion, including a line east to Hanna and a line north to Stettler. These early interconnecting lines were followed by a rural program, bringing electricity to an ever increasing number of farms.

Visionaries and Tireless Service

The CU story was unfolding more rapidly. Eugene Coste was followed by other men of vision, including E. G. Hill, C. J. Yorath, and H.R. Milner. These men came from various fields — engineering, law, even politics. When the old "farmer government" was replaced by Social Credit, the former

A Northwestern Utilities' crew installs a natural gas distribution line in downtown Edmonton (circa 1923).

premier, Richard Gavin Reid joined Canadian Utilities, where he stayed until his retirement many years later.

Further North

The dream continued to unfold in the fifties and sixties as the CU group expanded its service in existing areas, and was joined by energy enterprises in other areas. In 1957 the group purchased the power plant at Fort McMurray, and in 1958 took over The Yukon Electrical Company Limited and Yukon Hydro Company Limited in Whitehorse.

On June 19, 1961 Canadian Utilities was joined by Northland Utilities Limited, founded by Walter Schlosser and Warren Dubois in 1934. This company had been providing electric and natural gas service to northern communities.

The Seventies

The seventies brought new developments. Through a corporate restructuring approved by the shareholders on December 20, 1971, Canadian Utilities became the holding company and parent of Canadian Western Natural Gas Company Limited, Northwestern Utilities Limited, Northlands Utilities Limited, and a new company, Alberta Power Limited, which was formed to assume the electrical operations of Canadian Utilities.

Canadian Owned

During the years between the first and second world wars, it was almost impossible to get people in Alberta to invest in something like a local utility company. There wasn't a great deal of money around to be invested, and much of what was around was still going into the development of family farms or industries related to agriculture. To raise large amounts of money, financiers usually went to major world centres like London and New York. It was not surprising then, that the controlling interest in the CU group was held by an organization from outside Canada.

That has changed. In 1980 an Alberta company, ATCO Ltd. of Calgary, purchased the shares held by that organization, giving ATCO the controlling interest in Canadian Utilities. Today CU is one of the largest investor-owned utility companies in Canada and virtually 100% Canadian owned.

Start of the Eighties

Today the CU group represents total assets well in excess of one billion dollars, and employs more than 4,500 dedicated people who provide electric and natural gas service around the clock, from the U.S. border, all the way to Old Crow, 70 miles inside the Arctic Circle. The two major gas utilities, Canadian Western, and Northwestern, serve over one half million customers throughout Alberta. Gas sales are close to 400 billion cubic feet per year.

On the electric side, the number of customers buying power from CU passed the 128,000 mark in 1980, including more than 24,000 farm customers. Over 23,000 of those are members of 167 rural electrification associations. Total energy sales are up to nearly three billion kilowatt hours per year.

To the End of the Century

There are new challenges ahead for the eighties and nineties. CU is ready to meet them. Specialized subsidiaries have been formed to handle new demands. CU Engineering Limited concentrates on a variety of sophisticated services, ranging from feasibility studies to the design and operation of complex utility systems.

Moving into new realms of petroleum and petrochemical developments are two other subsidiaries — CU Ethane Limited and CU Resources Limited.

The founders of the CU group of enterprises have passed on the torch of energy service to a new group of leaders faced with a new set of challenges. But the corporate vision hasn't faded. The CU story is still unfolding.

CORPORATE INFORMATION

CANADIAN UTILITIES LIMITED
(Incorporated under the laws of Canada)

Board of Directors

W. L. Britton
Barrister and Solicitor
Bennett Jones
Caglary, Alberta

G. L. Crawford, Q.C.*
Barrister and Solicitor
McLaws & Company
Calgary, Alberta

E. W. King
President and Chief Executive Officer
Canadian Utilities Limited
Edmonton, Alberta

P. L. P. Macdonnell, Q.C.
Barrister and Solicitor
Milner & Steer
Edmonton, Alberta

D. R. B. McArthur*
Corporate Director
Edmonton, Alberta

W. S. McGregor*
President
Numac Oil & Gas Ltd.
Edmonton, Alberta

C. S. Richardson
Senior Vice-President, Finance
ATCO Ltd.
Calgary, Alberta

N. W. Robertson
Senior Vice-President and
Chief Operating Officer
ATCO Ltd.
Calgary, Alberta

R. D. Southern
President and Chief Executive
Officer
ATCO Ltd.
Calgary, Alberta

* member of audit committee

Officers and Staff Executives

R. D. Southern
Chairman of the Board

C. S. Richardson
Deputy Chairman of the Board

E. W. King
President and Chief Executive Officer

D. R. Brandt
Vice-President

A. M. Anderson
Secretary

H. N. Bottomley
Controller

P. R. Ladouceur
Treasurer

C. K. Sheard
Assistant Secretary

Subsidiary Company Executives

ALBERTA POWER LIMITED

E. W. King
President and Chief Executive Officer

Keith Provost
Senior Vice-President

R. H. Choate
Vice-President, Administration

D. B. Mitchell
Vice-President, Industrial Relations

J. E. A. Morin
Vice-President, Engineering and Construction

G. N. Paicu
Vice-President, Energy Supply

C. O. Twa
Vice-President, Customer Services

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
— and —
NORTHWESTERN UTILITIES LIMITED

E. W. King
President and Chief Executive Officer

J. H. Pletcher
Senior Vice-President

D. L. Weiss
Vice-President, Gas Supply

D. B. Mitchell
Vice-President, Industrial Relations

B. M. Dafoe
Vice-President and General Manager
Northwestern Utilities Limited

A. J. L. Fisher
Vice-President and General Manager
Canadian Western Natural Gas Company Limited

CU ENGINEERING LIMITED

D. M. Murray
General Manager

CU ETHANE LIMITED

D. R. Brandt
President

CU RESOURCES LIMITED

D. L. Weiss
Manager

Registered Head Office

10040 - 104th Street
Edmonton, Alberta, Canada
T5J 2V6
Telephone: (403) 420-7310

Transfer Agent and Registrar

Common Shares and Preferred Shares:
Montreal Trust Company
Halifax/Montreal/Toronto/Winnipeg
Calgary/Edmonton/Vancouver

Trustee and Registrar

Debentures:
National Trust Company, Limited
Montreal/Toronto/Winnipeg
Calgary/Edmonton/Vancouver

Stock Exchange Listings

Common Shares:
Toronto, Montreal and Alberta
Stock Exchanges

Preferred Shares:
10¼% second preferred Series A
9.24% second preferred Series B
7.30% second preferred Series C
10.24% second preferred Series D
10.12% second preferred Series E
Toronto and Montreal Stock Exchanges

5% preferred
4¼% Series preferred
6% Series preferred
Toronto Stock Exchange

Auditors

Peat, Marwick, Mitchell & Co.
2500 Alberta Telephone Tower
10020 - 100th Street
Edmonton, Alberta

Valuation Day

The Valuation Day price of Canadian Utilities' common shares adjusted for the stock split of September 15, 1972 was $9.31.

Annual Meeting

The annual meeting of shareholders will be held at 11:00 a.m., April 21, 1981 at the Hotel Macdonald, Edmonton, Alberta.

ATCO LTD.

ATCO Ltd. is a Calgary-based holding company whose organization of energy and resource-related companies operates worldwide. Its history began in 1946 when S. D. Southern, now chairman of the company, founded a small trailer rental operation in Calgary. From this entrepreneurial beginning sprang a network of horizontally and vertically integrated companies, each one characterized by a spirit of adventurous free enterprise.

ATCO's growth has been dramatic — both as a result of internal expansion and acquisition. Employing more than 8,000 people, the company is engaged in oil and gas exploration and development; contract drilling and well servicing; engineering consultation and project management; manufacturing and distribution of prefabricated structures; residential housing and building supply and in all areas of land and property development.

ATCO's acquisition of CU was consistent with ATCO's corporate mission — seeking to concentrate activities in the fields of energy and resources, primarily in North America. Thus, to its other operations, ATCO added the related fields of electricity generation and transmission and the supply and distribution of natural gas.

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